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Linear Programming Derived Optimization Strategies for Control of SOx from Coal-Fired Power Plants

PEDCO-Environmental, Inc, Cincinnati, OH

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16. ABSTRACT

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The LP results for two hypothetical power plant networks suggest that the use of flue gas desulfurization and coal cleaning as a combined strategy yields a reduction in SO_2 compliance costs if moderate capital costs can be tolerated. For a 3 plant system with a combined capacity of 1150 MW, the LP solution resulted in an incremental capital cost of 36.5 million and an 11 percent reduction in total annualized costs. Annualized costs for a large network of 7 plants (combined capacity 12,970 MW) could potentially be reduced 4.5 percent. This saving results from a 30 percent reduction in annualized SO_2 compliance costs.

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SUMMARY

A linear programming (LP) technique has been used to determine a least cost SO_2 control strategy for a network of coal-fired power plants. The general strategy consists of multi-stream coal cleaning in conjunction with the use of low sulfur coal supplies and flue gas desulfurization. The use of linear programming is demonstrated to be a convenient mechanism to rapidly identify the most economically attractive fuel redistribution/SO_2 control options. The structure of the technique is a transshipment model. The simplex algorithm is used to determine the minimum of an objective function which includes the major cost components of interest. Non-linear cost functions are handled with a heuristic approach.

The LP results for two hypothetical power plant networks suggest that the use of flue gas desulfurization and coal cleaning as a combined strategy yields a reduction in SO_2 compliance costs if moderate capital costs can be tolerated. For a 3 plant system with a combined capacity of 1150 MW, the LP solution resulted in an incremental capital cost of 36.5 million and an 11 percent reduction in total annualized costs. Annualized costs for a large network of 7 plants (combined capacity 12,970 MW) could potentially be reduced 4.5 percent. This saving results from a 30 percent reduction in annualized SO_2 compliance costs.

Parametric studies were made to determine the impact of changes in cost coefficients and in emission regulations on the optimum solution. Generally the control strategy and costs were not overly sensitive to changes within a reasonable range.

General procedures for the preparation of input data and for the adjustment of nonlinear cost functions are provided to assist potential users of LP models on actual networks. Recommendations have been presented to extend and refine the application of linear programming techniques to actual networks.

1.0 INTRODUCTION

1.1 MULTI-STREAM COAL CLEANING FOR SO_2 CONTROL

The primary purpose of this project was the development of an optimization strategy for control of SO_x emissions. It has been proposed that the use of physical coal cleaning in conjunction with flue gas desulfurization (FGD) and/or low sulfur fuels[a] could yield a reduction in SO_2 compliance costs for a network of boilers.[1,2] This hypothesis has been tested using linear programming techniques[a] with hypothetical boiler networks.

The results of linear programming (LP) analyses are useful in determining the potential cost savings available through use of multi-stream coal cleaning and fuel redistribution. Due to the large number of alternative fuel supply/pollution control options, calculation of the optimum strategy by a means other than by mathematical programming would be prohibitively expensive for large networks. Linear programming techniques provide a convenient mechanism for identifying the most economical approaches.

1.2 REPORT ORGANIZATION

The procedures used in applying LP techniques to complex power generating systems are given in Section 2. Then, analysis is performed using three hypothetical power plant networks of different complexities and generating capacities. The first network consists of one power plant having two boilers and four possible coal sources, one of which has a coal cleaning plant (CCP). Detailed explanation of this example is given in Section 3 in order to introduce the general procedures involved in the linear programming models. Then, the potential reductions in annualized costs

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[a]Definitions of selected terms are printed in Section 8, Glossary.

are determined for a 3 plant network and a 7 plant network as described in Section 4. The sensitivity of the 3 plant optimal solutions to various cost factors or technical constraints is discussed. The impact of each optimum solution on capital requirements is also reviewed. Selected LP computer runs are provided in Appendix A. A mathematical description of the LP approach is discussed in some detail in Appendix B.

It is assumed throughout this report that a 2.0 lb SO_2/MM Btu coal will be in compliance with an emission regulation of 2.0 lb SO_2/MM Btu. For example, if a monthly averaging time is being utilized and, if due to the variation of these monthly averages, a coal with an average of 1.7 lb SO_2/MM Btu is required for compliance with the regulation, then this complying coal will be designated as 2 lb SO_2/MM Btu coal. With this assumption, there is no need to extend the discussion to consider the variability of sulfur content and its implication on meeting emission regulations. The inclusion of sulfur variability would add another dimension to the scope of this study.

The utilization of LP models is discussed in Section 5. The type and format of input data necessary for a run is presented. The use of iteration procedures to arrive at a technically feasible and economically optimal solution is also discussed.

1.3 LIMITATIONS OF THE APPROACH

There are several practical limitations to the use of linear programming models in this study for evaluating multi-stream coal cleaning or other component processes involved in power generation. Capital costs and total annualized costs were not optimized simultaneously. The total annualized cost may be minimized subject to a constraint

on capital cost or multiple objective functions may be optimized by a succession of linear programming problems. The models used in this report are based on annualized costs and are useful only in systems which can tolerate moderate capital expenses in order to minimize the overall annualized costs. In certain cases a utility may not have access to the necessary capital for an "optimum" strategy.

The linear programming models herein are limited to the extent that site specific factors are taken into account. While the approach used in this report contains some flexibility to incorporate these factors, the solutions are not strictly applicable to a specific boiler or power plant network. A slight modification in the network fuel supply/pollution control strategy in a specific system may be necessary to accomodate special conditions such as water availability, power demand patterns, and control equipment retrofit problems.

There are a large number of commercially available FGD processes and coal cleaning processes which could be used in a combined strategies approach. Selection of the specific design and the specific operational conditions is a distinct optimization problem. Optimization of component processes within the overall problem is not considered in this study. LP as used in this project is useful in indicating the general region of the optimum solution but does not yield specific information about any component processes. Optimization of component processes may necessitate a rerun of the LP as a result, for example, of either a change in the coal characteristics or the cost of cleaning the coal in the case of a proposed cleaning process.

2.0 PROBLEM DESCRIPTION

Established techniques for SO_2 control at coal fired industrial and utility boilers consist of either utilization of naturally occurring low sulfur coal or utilization of one of the FGD processes. With the increasing costs of low sulfur coal supplies (particularly western coals) and the high cost of desulfurization, SO_2 compliance costs are increasingly important components of overall power generation cost. It has been proposed that use of physical coal cleaning in conjunction with flue gas desulfurization and/or natural low sulfur fuels could yield a substantial reduction of SO_2 compliance costs for a network of boilers.[1,2] This combined strategy would emphasize coal cleaning and fuel supply redistribution with minimum reliance on desulfurization systems and/or low sulfur coal supplies. Analysis of combined strategy options are facilitated by using linear programming methods.

The economics of a combined strategy partially depends on the effective utilization of "waste coal" at a cleaning plant. At the present time, coal is generally cleaned only to the extent necessary to achieve acceptable ash content without excessive loss of Btu's to the waste stream(s). The output streams from conventional single-stream plants usually consist of the following:

1. A "clean" stream containing 80 to 95 percent of the total Btu's and 70 to 90 percent of the total input weight. The ash content is generally 50-75 percent of that for raw coal, while the sulfur content is 60 to 90 percent of that for raw coal.

2. A "waste" product containing the remainder of the input Btu's and material. The sulfur content and ash content can be exceptionally high (20 to 100 lb SO_2/MM Btu and 40 to 80 percent ash).

By cleaning at lower specific gravities (1.3 to 1.6 instead of 1.7 to 1.9) it is possible to substantially modify the distribution of Btu's, material weight, sulfur, and ash in a manner which makes multi-product physical coal cleaning more amenable to a combined strategy approach. Between 10 and 60 percent of the carbonaceous matter and a similar fraction of the total input material weight can be distributed into a middling product stream. The "reject" stream still contains very high levels of sulfur and ash. The reject stream typically has too high of a sulfur and ash content and too low of a Btu content to justify utilization. The availability of two coal streams (the clean and middling streams) with moderate sulfur levels minimizes Btu loss in cleaning and creates a large number of fuel supply options.

The generation of multiple coal streams of varying qualities in addition to the complexity already involved in selection of FGD or low sulfur coal supplies results in a very large number of possible SO_2 control options for a network of boilers. Linear programming techniques provide a convenient mechanism to rapidly identify the most attractive approaches. The structure of the problem is described by Figure 2-1.

The boilers, P in number, are to be supplied with sufficient coal to meet their hourly demands by their customers. In order to comply with the emission regulations they may use coal directly from a supplier, from a physical coal cleaning plant (CCP) and/or utilize an FGD system. The number of coal cleaning plants will be some number between 0 and N, the number of suppliers. The number of FGD systems

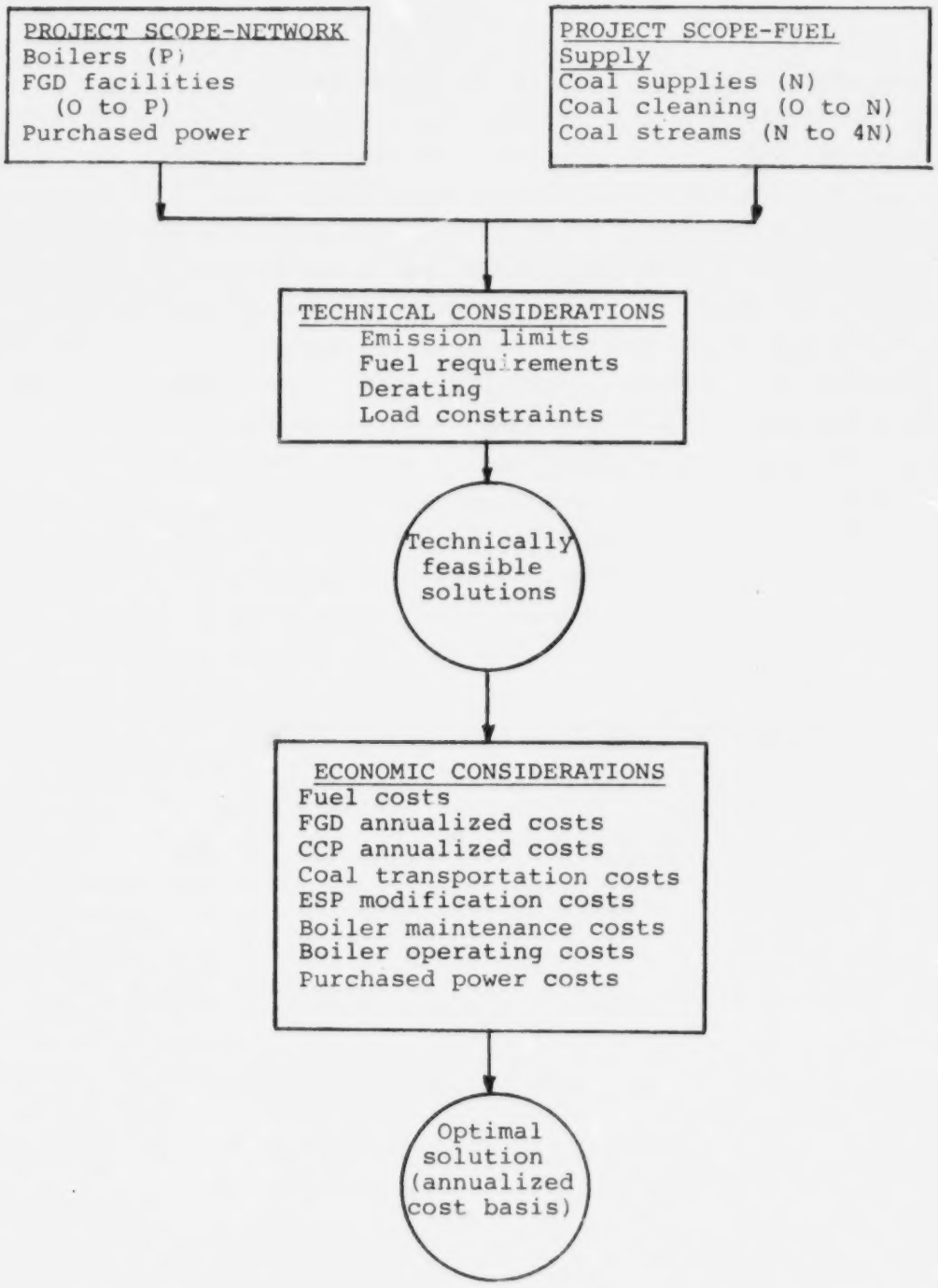

Figure 2-1. Linear programming problem

will be less than or equal to P, the number of boilers.

PEDCo Environmental, Inc. and its subcontractor, Systems Sciences, Inc., have selected a transshipment model and have used the IBM-MPS linear programming system in obtaining an optimal solution.[a] This technique utilizes the SIMPLEX algorithm to derive the minimum and/or maximum of an objective function within a regio. defined by a set of constraints.[3] The objective function basically defines a problem of shipping a commodity (coal) from multiple supply points through a network of intermediate points to one or more demand points. Each arc between two points can be associated with a cost and/or a constraint on the flow between the points. An illustration of a relatively simple case involving P boilers and N coal suppliers (each with physical coal cleaning plants) is shown in Figure 2-2.

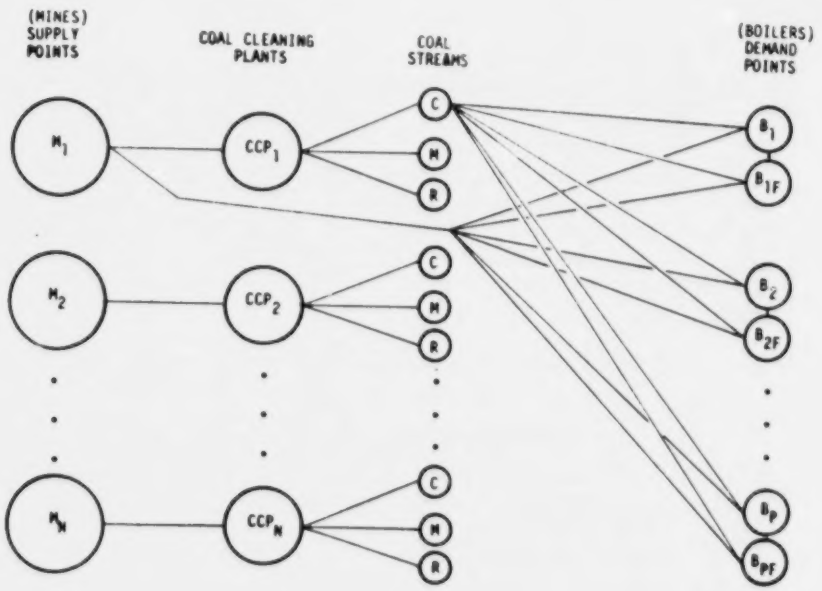

Figure 2-2. Transshipment model for P demand points - N supply points

[a]There are other LP systems, e.g., the FMPS for use on the UNIVAC-1110 computer system.

The coal from any mine may be sent directly to any of the P boilers or it may first be cleaned. If cleaned, it is separated into one of three coal streams, clean, middling and reject, and from there is sent to any of the P boilers. The reject stream is not used in any of the boilers.

The figure shows several of the possible paths of coal from mine 1. The coal is sent from the mine to any boiler or to the coal cleaning plant where the paths from coal stream C are indicated. All other mines and coal cleaning plants/streams have similar coal flows emanating from them.

Each boiler is divided into one with and one without an FGD system to permit the possibility that all, part, or none of the flue gases may be cleaned.

Generalized equations for the objective function Z and constraint equations are presented in equations 1 and 2-1 through 2-M.

$$Z = c_1x_1 + c_2x_2 + \cdots + c_Nx_N \qquad \text{Equation 1}$$

$$a_{11}x_1 + a_{12}x_2 + \cdots + a_{1N}x_N \left\{ \begin{matrix} \leq \\ \geq \\ = \end{matrix} \right\} b_1 \qquad \text{Equation 2-1}$$

$$a_{21}x_1 + a_{22}x_2 + \cdots + a_{2N}x_N \left\{ \begin{matrix} \leq \\ \geq \\ = \end{matrix} \right\} b_2 \qquad \text{Equation 2-2}$$

$$\cdots \qquad \cdots$$

$$a_{M1}x_1 + a_{M2}x_2 + \cdots + a_{MN}x_N \left\{ \begin{matrix} \leq \\ \geq \\ = \end{matrix} \right\} b_M \qquad \text{Equation 2-M}$$

The coefficients denoted by a's in equations 2-1 through 2-M are determined by the physical characteristics of the network. Constraint equations are used to define fuel requirements, SO_2 emission limits, mine capacities, and other necessary restrictions. The symbols, x_1, x_2, ... , x_N, represent coal-flow variables in million Btu, (MM Btu); for example, x_1 might be the flow of coal from the first mine (or source) to the first boiler. The objective function Z is the total annualized cost for the examples in this report. The coefficients denoted by c's in equation 1 are the input cost coefficients. Each coefficient corresponds to a sum of fuel, transportation, control system, and other pertinent costs, and all are on a consistent basis ($ per million Btu). The accuracy of these input cost coefficients determines the overall accuracy of the linear programming results. Estimation of input cost data for FGD systems, coal cleaning plants, electrostatic precipitator modifications, and other costs is described in Section 5. The major cost components in the linear programming model are:

1. Coal costs (@ source).
2. Fuel transportation cost.
3. Flue gas desulfurization annualized cost.
4. Coal cleaning plant annualized cost.
5. Modified electrostatic precipitator annualized cost.
6. Boiler operating and maintenance cost.
7. Purchased power cost.

Linear programming techniques require that the objective function and all of the constraint equations be linear functions of the structural variables. This complicates the computation procedure since some of the cost equations are nonlinear functions of coal throughput. For example, general annualized cost for FGD systems and physical coal cleaning plants can be roughly approximated by an equation of the

form,

$$c = ax^{0.4} \qquad \text{Equation 2-3}$$

where

c = Annualized cost, $.

a = Cost coefficient, $/MM Btu.

x = Coal throughput, MM Btu.

Furthermore, there are several other nonlinearities inherent in coal combustion and pollution control. These include derating requirements, the cost for ESP modification as a function of average sulfur content, and the boiler maintenance costs as a function of ash properties and other factors. An iterative approach was used in this study in order to consider these nonlinearities. This is discussed in detail in Section 5.

3.0 SINGLE PLANT SCENARIO

A single plant example is provided to illustrate the approach for obtaining an optimal solution. The following plant characteristics were assumed, based on an actual plant.

	Boiler 1	Boiler 2
Maximum continuous capacity, MW	360	900
Capacity factor, %	37	65
Boiler remaining life, years	12	19
Fuel consumption/hour, tons/hour	192.2	480.6
Flue gas rate, cfm	1,152,000	2,790,000
Flue gas temperature, ^{o}F	300	300
Estimated duct run, ft.	-	800
Heating value of fuel, Btu/unit	10,300	10,300
Efficiency of FGD system, %	-	85
Emission regulation, lb SO_2/MM Btu	4	1.8

In many cases the emission regulations of 4 and 1.8 lb SO_2/ MM Btu would be the same for two boilers within the same plant. However, in this example they are assumed to be different in order to yield a solution which may utilize more than one source of coal from the four assumed sources described in Table 3-1. These data are assumed based on common coal supplies and prevailing costs. The values 4 and 1.8 are changed in later examples in order to determine the impact on the annualized cost of the fuel, transportation, and SO_2 control.

Using these plant/boiler characteristics a computer model for flue gas desulfurization was run to estimate the annualized costs (see Section 5.0). The coal washability characteristics for the Eastern Midwest Coals, i.e., the amount of coal in each stream (clean, middling, and residual or reject), the heating content, Btu/lb, and lb SO_2/MM Btu

Table 3-1. COAL CHARACTERISTICS AND COSTS[a]

MINE SOURCE	Source: Region and Coal Type	GHV[b] Btu/lb	Sulfur %	lb SO_2/MM Btu	Ash %	At mine cost $/MM Btu	Transportation costs $/MM Btu
1	Eastern low sulfur	12,500	0.80	1.28	12.0	1.60	0.35
2	Western low Btu low sulfur	8,150	0.50	1.23	8.0	0.42	1.08
3	Western high Btu low sulfur	12,300	0.80	1.30	13.0	0.97	0.72
4	Eastern Midwest high sulfur	12,190	3.90	6.50	14.2	0.90	0.15

[a]Coal quality based on Bureau of Mines data; cost data based on typical costs reported for the respective coal producing regions.

[b]Gross heating value.

for each stream, and the coal cleaning plant design are briefly described in Section 5. These data are used in a computer model to estimate the annualized cost of the coal cleaning plant.

The coal costs and transportation costs are assumed as given in Table 3-1. These fuel costs are subject to considerable variation and the resulting optimal solutions are clearly dependent on these assumed costs. However, the emphasis in this study is on the methodology of the approach and not on a particular solution for assumed costs. The costs will be varied to yield the sensitivity of the optimal solution to these changes.

In the approach used, a coal cleaning plant may be assumed for each coal source. The coal may be cleaned and transported to the power plant, or it may be sent directly from the mine to the power plant without any preparation. In this particular example, only the Eastern Midwest coal has the option to be cleaned; i.e., the optimal solution may select this strategy. In addition the general approach would select whether or not an FGD system is to be used with each boiler/plant. To do this, two receptors are assumed for each boiler, one with and one without an FGD. These two receptors are then combined into a single boiler with the appropriate proportion of the flue gases scrubbed in order to comply with the emission regulations. An FGD system was arbitrarily restricted to boiler 2 due to the lower emission regulation of that boiler.

The approach is flexible in that it permits assigning costs to each phase of the coal production, coal cleaning, transportation, and flue gas cleaning. It permits the combined use of coal cleaning with FGD or restricts the combined use by appropriate cost coefficients for a particular coal stream.

3.1 EXPLANATION OF COMPUTER OUTPUT

The objective function and constraint (including the conservation) equations are given in this subsection. The coal characteristics and costs for this problem are taken from Table 3-1. The costs for coal cleaning and flue gas desulfurization are obtained by use of computer models described in Section 5. The estimated costs are $0.10/MM Btu for coal cleaning and $0.60/MM Btu for flue gas desulfurization.[a] The washability characteristics are based on results reported in reference 1 (see Section 5 for further details on washability).

The statement of the problem is as follows. It is desired to minimize the total annualized cost by determining the optimum allocation of the four coals of Table 3-1, and the use of coal cleaning and FGD systems in order to comply with the regulations, 4 and 1.8 lb SO_2/MM Btu for Boilers 1 and 2, subject to the constraints,

Coal available at each source (mine) $\leq$ 70,000,000 MM Btu, i.e., there is sufficient coal at each source (mine) to provide for the operation of both boilers.

Boiler 1 demand $\leq$ 34,690,000 MM Btu per year.

Boiler 2 demand $\leq$ 86,724,000 MM Btu per year.

Plant demand $\geq$ 69,206,000 MM Btu per year.

The objective and constraint functions are given below in the same form as they are used in the computer program and followed by the derivation of the coefficients in the equations.

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[a]The $0.60/MM Btu cost for an FGD system was estimated on the basis of the size of the FGD system resulting from an initial run at $0.50/MM Btu.

Objective Function: (Cost)

Total annualized cost = 2.015 S1B1 + 2.015 S1B2
+ 2.615 S1B2F + 1.630 S2B1 + 1.630 S2B2
+ 2.230 S2B2F + 1.755 S3B1 + 1.755 S3B2
+ 2.355 S3B2F + 1.010 S4C + 1.050 S4B1
+ 0.140 S4AB1 + 0.160 S4MB1 + 0.590 S4RB1
+ 1.050 S4B2 + 0.140 S4AB2 + 0.160 S4MB2
+ 0.590 S4RB2 + 1.650 S4B2F + 0.740 S4AB2F
+ 0.760 S4MB2F + 1.190 S4RB2F

Equation 3-1

The notation is

S1B1: denotes coal from source 1, S1, to boiler 1, B1,

S1B2F: denotes coal from source 1 to boiler 2 with an FGD.

S4C: denotes coal from source 4 to coal cleaning plant.

S4CA: coal from source 4 to coal cleaning plant (CCP) and coal clean stream (A)[a] from the CCP.

S4CM: coal from source 4 to coal cleaning plant (CCP) and middling stream (M) from the CCP.

S4CR: coal from source 4 to coal cleaning plant (CCP) and reject stream (R) from the CCP.

S4AB2F: coal from source 4, coal cleaning plant A or clean stream, to boiler 2 with FGD.

The derivation of the coefficients in the objective function is shown in Table 3-2. The transportation cost of the three streams leaving the CCP is determined by the Btu/lb, and thus increases as the Btu/lb decreases from that of the clean stream. The coal characteristics for these three streams are given in Table 3-3. These were calculated based on float sink data for an Eastern Midwest region mine.

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[a] In later sections the clean coal is denoted by C and not A.

Table 3-2. COMPUTATION OF COEFFICIENTS IN THE OBJECTIVE FUNCTION

Variable	Coal	Clean	Transp	FGD	ESP*	TOTAL
S1B1	1.60	0	.35	0	.065	2.015
S1B2	1.60	0	.35	0	.065	2.015
S1B2F	1.60	0	.5	.60	.065	2.615
S2B1	.42	0	1.08	0	.13	1.630
S2B2	.42	0	1.08	0	.13	1.630
S2B2F	.42	0	1.08	.60	.13	2.230
S3B1	.97	0	.72	0	.065	1.755
S3B2	.97	0	.72	0	.065	1.755
S3B2F	.97	0	.72	.60	.065	2.355
S4C	.90	.10	.01	0	0	1.010
S4B1	.90	0	.15	0	0	1.050
S4AB1	0	0	.14	0	0	0.140
S4MB1	0	0	.16	0	0	0.160
S4RB1	0	0	.59	0	0	0.590
S4B2	.90	0	.15	0	0	1.050
S4AB2	0	0	.14	0	0	0.140
S4MB2	0	0	.16	0	0	0.160
S4RB2	0	0	.59	0	0	0.590
S4B2F	.90	0	.15	.60	0	1.650
S4AB2F	0	0	.14	.60	0	0.740
S4MB2F	0	0	.16	.60	0	0.760
S4RB2F	0	0	.59	.60	0	1.190

* Assumed ESP modification costs

Table 3-3. COAL CHARACTERISTICS FOR THE CLEANED COAL

	lb SO_2/MM Btu	Btu/lb	lb/coal / 100 lb feed	% ash
Clean stream, A	3.8	13,358	64.60	5.9
Middling stream, M	8.54	11,186	30.47	20.76
Reject stream, R	109.00	3,097	4.93	78.97
Raw coal	6.50	12,190	100.00	14.2

Thus the transport costs of the three streams are $0.14, $0.16, and $0.59/MM Btu for the clean, middling, and reject streams, respectively. The transportation cost for the clean stream is determined by the product of $0.15 (the average cost) by 12,190/13,358 = $0.14, for the middling stream by $0.15 × 12,190/11,186 = $0.16, and for the reject stream by $0.15 × 12,190/3,097 = $0.59.

Constraint Equations

Mine: (M1, M2, M3, M4)

The following four constraints state that the coal supply from each source is less than or equal to 70,000,000 MM Btu, i.e., sufficient coal to meet the plant demand on the following page.

1. $S1B1 + S1B2 + S1B2F \leq 70{,}000{,}000$ MM Btu
2. $S2B1 + S2B2 + S2B2F \leq 70{,}000{,}000$ MM Btu
3. $S3B1 + S3B2 + S3B2F \leq 70{,}000{,}000$ MM Btu
4. $S4C + S4B1 + S4B2 + S4B2F \leq 70{,}000{,}000$ MM Btu

Equation 3-2

Boiler: (B1, B2)

The following two constraints state that the coal consumed by each boiler is not to exceed a specified amount in MM Btu.

1. $S1B1 + S2B1 + S3B1 + S4B1 + S4AB1 + S4MB1 + S4RB1 \leq 34{,}690{,}000$ MM Btu

2. $S1B2 + S1B2F + S2B2 + S2B2F + S3B2 + S3B2F + S4B2 + S4AB2 + S4MB2 + S4RB2 + S4B2F + S4AB2F + S4MB2F + S4RB2F \leq 86{,}724{,}000$ MM Btu

Equation 3-3

Plant: (PL)

This constraint ensures that the plant meets the total power demand.

$$S1B1 + S1B1F + \ldots + S4RB2F \geq 69{,}206{,}000 \text{ MM Btu}$$

Equation 3-4

SO_2 Emissions Regulation: (EC1, EC2)

These two regulations ensure that each boiler complies with the sulfur dioxide emission regulations. For each boiler,

actual lb SO_2/MM Btu - lb SO_2/MM Btu allowed by regulation ≤ 0.

For a boiler with an FGD system with an assumed 85 percent efficiency, this inequality is

(actual lb SO_2/MM Btu)(0.15) - lb SO_2/MM Btu allowed by regulation ≤ 0.

For the actual calculations involved in computing the coefficients for these constraints see Table 3-4.

Table 3-4. COMPUTATION OF COEFFICIENTS IN SO_2 REGULATION CONSTRAINTS

Variable	Actual Lb[a] SO_2/MM Btu	Lb SO_2/MM Btu Emission Regulations	Difference
S1B1	1.28	4.0	-2.72
S2B1	1.23	4.0	-2.77
S3B1	1.30	4.0	-2.70
S4B1	6.5	4.0	2.5
S4AB1	3.8	4.0	-0.2
S4MB1	8.54	4.0	4.54
S4RB1	109.0	4.0	105.0
S1B2	1.28	1.8	-0.52
S1B2F	0.192	1.8	-1.608
S2B2	1.23	1.8	-0.57
S2B2F	0.185	1.8	-1.615
S3B2	1.3	1.8	-0.50
S3B2F	0.195	1.8	-1.605
S4B2	6.5	1.8	4.70
S4AB2F	3.8	1.8	2.0
S4MB2	8.54	1.8	6.74
S4RB2	109.00	1.8	107.20
S4B2F	0.975	1.8	-0.825
S4AB2F	0.57	1.8	-1.23
S4MB2F	1.28	1.8	-0.519
S4RB2F	16.35	1.8	14.55

[a]Multiplied by 0.15 when the variable corresponds to a boiler utilizing an FGD system to reflect an 85 percent removal efficiency.

Boiler 1: $- 2.72\ S1B1 - 2.77\ S2B1 - 2.7\ S3B1 + 2.5\ S4B1$
$- 0.2\ S4AB1 + 4.54\ S4MB1 + 105.0\ S4RB1 \leq 0.$

Boiler 2: $- 0.52\ S1B2 - 1.608\ S1B2F - 0.57\ S2B2$
$- 1.615\ S2B2F - 0.50\ S3B2 - 1.605\ S3B2F$
$+ 4.7\ S4B2 + 2.0\ S4AB2 + 6.74\ S4MB2$
$+ 107.2\ S4RB2 - 0.825\ S4B2F - 1.23\ S4B2$
$- 0.519\ S4MB2F + 14.55\ S4RB2F \leq 0$

Equation 3-5

Washability: (CCA, CCM, CCI

These equalities ensure that the three coal streams leaving the CCP are in the proper proportions as given in Table 3-3.[a] 70.8 percent of the Btus entering the CCP (S4C) leaves in the clean stream, S4CA; 28.0 percent leaves in the middling stream, S4CM; and 1.2 percent leaves in the reject stream, S4CR. These coal cleaning results are based on the results stated in reference 1.

Clean Stream: $S4CA - 0.708\ S4C = 0$
Middling Stream: $S4CM - 0.280\ S4C = 0$
Reject Stream: $S4CR - 0.012\ S4C = 0$

Equation 3-6

Conservation of coal from CCP: (BTUA, BTUM, BTUR)

These inequalities ensure that the amount of coal leaving the CCP is no more than the amount that enters the CCP. The coal in each of the three streams (A, M, and R) can be sent to any of the three receptors , Boiler 1, 2 or 2F.

Clean: $S4AB1 + S4AB2 + S4AB2F - S4CA \leq 0$
Middling: $S4MB1 + S4MB2 + S4MB2F - S4CM \leq 0$
Reject: $S4RB1 + S4RB2 + S4RB2F - S4CR \leq 0$

Equation 3-7

[a]Note that the distribution values in Table 3.3 provided in (lbs coal/100 lbs feed) have been converted to (Btus/Btus) for consistency with the LP equations. (i.e. (13,358 Btu/lb x .646 lb coal/lb feed) ÷ (12,190 x .1 lb coal/lb feed = .708)

The above data, coefficients and variable names, become inputs to the Mathematical Programming System (MPS) which solves for the most economical allocation of the coals, CCP, and FGD systems while complying with the stated constraints.

Two runs were made in order to converge to a solution for which the estimated costs of coal cleaning and the FGD systems (both of which depend on throughput) are consistent with the costs for the sizes of the two systems implied by the optimal solution. Only the second run is given here.

The computer printout from MPS is in the form of Table 3-5. Section 1 - Rows in the upper portion of the table give the following information:

1. Constraint name in column 2.
2. Status of the constraint at optimality:
   - BS: in the basis
   - EQ: nonbasis fixed
   - LL: nonbasis, rhs at lower limit
   - UL: nonbasis, rhs at upper limit
3. Right hand side of constraint at optimality in column 4
4. In column 5 difference between optimal RHS and upper/lower bound on RHS as stated in the constraints
5. Upper and lower bound on the constraints in columns 6 and 7
6. Column 8, DUAL ACTIVITY, can be interpreted as follows:

   The values in this column are the increases (decreases) in the objective function, total annualized cost, for a unit increase in the corresponding right-hand side of constraint If the value is zero as in lines 2 through 5, an increase in the constraint from say

Table 3-5. COMPUTER PRINTOUT OF OPTIMAL LP SOLUTION - ONE PLANT SCENARIO

SECTION 1 - ROWS

NUMBER	...ROW..	AT	...ACTIVITY...	SLACK ACTIVITY	..LOWER LIMIT.	..UPPER LIMIT.	.DUAL ACTIVITY
1	COST	BS	95220.40157	95220.40157-	NONE	NONE	1.00000
2	MINE1	BS	.	70000.00000	NONE	70000.00000	.
3	MINE2	BS	.	70000.00000	NONE	70000.00000	.
4	MINE3	BS	.	70000.00000	NONE	70000.00000	.
5	MINE4	BS	69891.62385	108.37615	NONE	70000.00000	.
6	BOILER1	UL	34689.59961	.	NONE	34689.59961	.30356
7	BOILER2	BS	34516.15234	52207.84766	NONE	86724.00000	.
8	PLANT	LL	69205.75195	.	69205.75195	NONE	1.52806-
9	SO2A1	UL	.	.	NONE	.	.06980
10	SO2A2	UL	.	.	NONE	.	.14780
11	AW	EQ	.	.	.	.	1.09246
12	MW	EQ	.	.	.	.	.84477
A 13	BW	EQ	.	.	.	.	.
14	S4AC	UL	.	.	NONE	.	1.09246
15	S4MC	UL	.	.	NONE	.	.84477
16	S4BC	BS	685.87190-	685.87190	NONE	.	.

SECTION 2 - COLUMNS

NUMBER	.COLUMN.	AT	...ACTIVITY...	..INPUT COST..	..LOWER LIMIT.	..UPPER LIMIT.	.REDUCED COST.
17	S1B1	LL	.	2.01500	.	NONE	.60064
18	S1B2	LL	.	2.01500	.	NONE	.41008
19	S1B2F	LL	.	2.61500	.	NONE	.84927
20	S2B1	LL	.	1.63000	.	NONE	.21215
21	S2B2	LL	.	1.63000	.	NONE	.01769
22	S2B2F	LL	.	2.23000	.	NONE	.46309
23	S3B1	LL	.	1.75500	.	NONE	.34203
24	S3B2	LL	.	1.75500	.	NONE	.15304
25	S3B2F	LL	.	2.35500	.	NONE	.58972
26	S4C	BS	57155.99184	1.01000	.	NONE	.
27	S4CA	BS	40466.44222	.	.	NONE	.
28	S4CM	BS	16003.67772	.	.	NONE	.
29	S4CB	BS	685.87190	.	.	NONE	.
30	S4B1	BS	2569.59997	1.05000	.	NONE	.
31	S4AB1	BS	32119.99964	.14600	.	NONE	.
32	S4MB1	LL	.	.16600	.	NONE	.10317
33	S4BB1	LL	.	.59000	.	NONE	6.69460
34	S4B2	LL	.	1.05000	.	NONE	.21660
35	S4AB2	BS	8346.44258	.14000	.	NONE	.
36	S4MB2	LL	.	.16000	.	NONE	.47289
37	S4BB2	LL	.	.59000	.	NONE	14.90618
38	S4B2F	BS	10166.03204	1.65000	.	NONE	.
39	S4AB2F	LL	.	.74000	.	NONE	.12260
40	S4MB2F	BS	16003.67772	.76000	.	NONE	.
41	S4BB2F	LL	.	1.19000	.	NONE	1.81244

70×10^6 to 70,000,001 MM Btu results in no change in cost because there is already slack activity in each case. However, a unit increase in the boiler 1 capacity will result in a decrease of 0.30912 units in the objective function, provided the current optimal basis remains feasible (see reference 8 for a discussion of the dual problem).

Section 2 - Columns in the bottom section of the table give similar information as that in Section 1, but refer to the variables rather than constraint equations.

1. Variable name in column 2.
2. In column 3 is the status of the variable, i.e.,
   - BS: variable is in the basis
   - FR: nonbasis free
   - LL: variable is nonbasic and at lower bound
   - UL: variable is nonbasic and at upper bound
3. In the ACTIVITY column is the value of the corresponding variable in the optimal solution. This variable is the number of Btu in billions (10^3 millions) per year that are in each stream. Refer to Figure 3-1 for a schematic representation of the optimal solution. The flowrate is given above the arc and the corresponding costs of transshipment, $/MM Btu, are given below the arc. The coal cleaning and FGD costs are shown below the corresponding circles (nodes) of the network.
4. In the last column, column 8, the reduced cost is given. The usefulness of this value can be appreciated when seen in the following manner.

   This is the quantity by which the optimal solution would increase per unit increase of the associated variable if that variable were allowed to enter the basis. (NOTE: Reduced costs for variables in the basis are zero.)

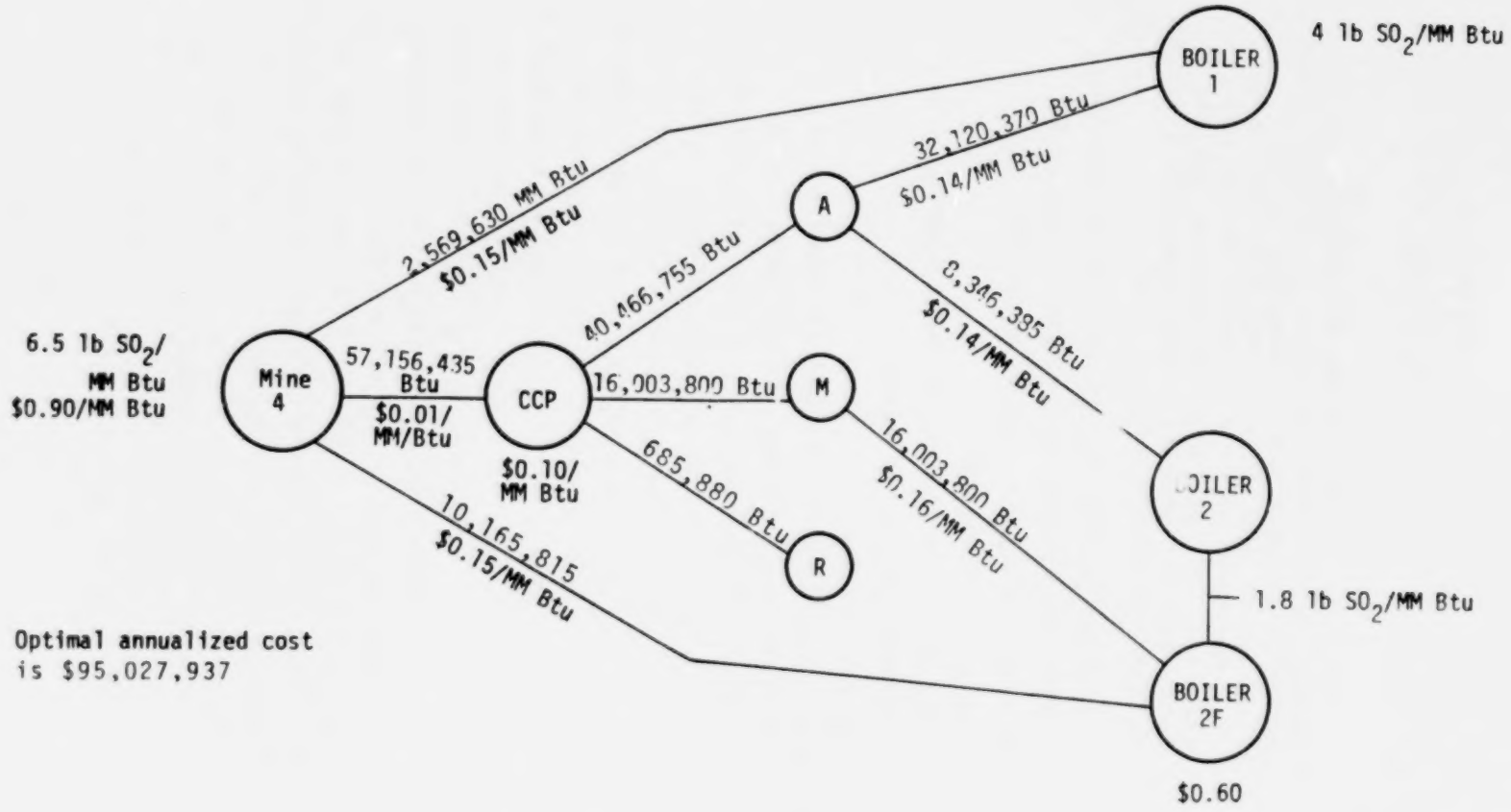


Figure 3-1. Optimal solution for single plant scenario-case 1.

Since this is a minimization problem, it is not desired to have an increase, but rather a decrease, in the optimal solution, and therefore, at optimality all reduced costs should be zero or positive.

If the input costs for any variable are reduced by less than the corresponding amount in the reduced costs column, then the current solution will remain optimal. If, however, any one of the input costs is reduced by more than the reduced costs, then the current solution will no longer remain optimal. For example, one solution was obtained with the input cost for S1B2 reduced by $0.60, which is more than the associated reduced cost of $0.41008 and the solution was altered, causing mine 1 (source 1) coal to be used. It is clear that a very small reduction in the cost of the coal from source 2 to boiler 2 will alter the solution because the reduced cost is $0.01769 per million Btu.

This section also gives the allocation of coal from the source to the coal cleaning plant and ultimately to each boiler. The only coal allowed to be cleaned is that from source 4 (Midwest coal). The other coal sources produce low sulfur coals and do not require cleaning to meet SO_2 regulations.

3.2 SENSITIVITY ANALYSIS

From previous discussion it is possible to make several remarks concerning the sensitivity of the optimal solution to changes in the costs. However, if the change in any one of the costs exceeds the corresponding reduced cost in Table 3-2, then the solution is altered. Several runs were made in which the solution was changed by selected changes in several parameters. These changes are indicated in Table 3-6. Case 1 represents the baseline case or the solution of the problem as originally stated in this section. Cases 2 through 7

Table 3-6. PARAMETER CHANGES MADE IN SINGLE PLANT SCENARIO

Case no.	Parameter	Change in parameter	Optimum annualized cost
1	Baseline case	No changes	$ 95,027,937
2	Cost of mine 1 coal	Reduced from $1.60 to $1.00/MM Btu	90,073,457
3	Emission regulation on Boiler 1	Reduced from 4 to 3 lb SO_2/MM Btu	99,932,620
4	Emission regulation on Boiler 2	Reduced from 1.8 to 1.2 lb SO_2/MM Btu also FGD increased to 0.70	100,480,811
5	Boiler 2, all flue gases cleaned, no coal cleaning	FGD used on all flue gases	102,920,308
6	FGD	FGD cost increased to $0.70/MM Btu	96,985,723
7	Fuel and transportation costs	No emission regulations, source 4	72,666,040

represent various changes from this case, such as cost of coal (Case 2), change in emission regulations (Cases 3 and 4), FGD used 100% on Boiler No. 2 (Case 5), change in FGD annualized cost (Case 6). Case 7 is one with no emission regulations, i.e., using the least expensive coal and transportation costs. The difference between Case 1 and Case 7 is the annual compliance cost, i.e., $22,361,897. These parameter changes are useful for relating the cost of compliance with changes in regulations, cost of fuels, and/or strategies with respect to cleaning coals or flue gases.

4.0 MULTIPLE PLANT SCENARIOS

The economic potential of combined strategies derived from linear programing has been evaluated using two hypothetical power plant networks. Both cases closely simulate actual systems (or parts of systems) so that the LP results can be compared with real costs. The potential impact of the combined strategy has been determined by comparison of the LP least cost solution with the costs for the present "non-optimized" base case.

The first scenario involves a rather simple network of 3 plants (5 boilers total) with a combined generating capacity of only 1150 megawatts. The primary purpose in studying this example is to determine if the LP results could be economically applied to a small system which could not bear substantial capital expense. The network which serves as the model for this scenario is subjected to stringent SO_2 emission regulations which supposedly require either high quality coal or flue gas desulfurization.

Power plant operators do not have the luxury of changing the basic SO_x control strategies on a frequent basis. Therefore, several studies were done using the three plant example to determine how LP results compared with non-optimized base case costs when the relative costs of coal supplies change or when the SO_2 regulations are modified. These analyses address the justified concern of plant operators that "optimal" approaches adopted in 1977 could become obsolete in the time necessary to complete system adjustment.

The second scenario involves a very large network of 7 plants with a combined generating capacity of 12,970 megawatts. Obviously the economics of scale with respect to FGDs and CCPs have a considerably smaller impact in the large network example than in the smaller network which is less than 10% its size. The objective of this example is to determine if LP models can be conveniently applied to a network composed of two separate utility companies. The equitable distribution of annualized cost savings and capital cost expenses is a major issue in the large network analyses. A further objective of this example is to determine if the complexity of a large network creates problems in preparing and applying LP models and in the interpretation of the results.

In both the small and large network scenarios, the cost data have been inflated to a 1980 basis using a factor of 1.4 applied to 1977 costs. The rationale is that it would take 2 to 3 years to complete installation of component systems (FGDs, CCPs, modified ESPs) used in a combined strategy.

The power demand in both examples has arbitrarily been assumed to be 63% of rated capacity. This value is based on a weighted average of 60% during 22 hours and 100% during the 2 hour peak demand period. Due to the diurnal variation in power demand, it was necessary to run 2 LP computer runs for each weighted average LP result. This somewhat cumbersome procedure is necessary to insure that an optimal solution based primarily on 60% load still provides compliance with SO_2 regulation at 100% load.

While the scenarios are based on actual systems, it should be noted that the LP results are not strictly applicable.

No attempt has been made to consider some site specific factors which conceivably influence cost.

4.1 SMALL NETWORK SCENARIO

The three plant network used in this example represents the minimum size power plant system expected to benefit from a linear program derived combined strategy SO_2 control approach. With a total generating capacity of 1150 MW, this network is smaller than many existing single power plants.

The hypothetical network consists of five boilers at three plants, all located in a hundred mile radius of a midwestern city. Data concerning this network are provided in Table 4-1.

Table 4-1. SMALL NETWORK DESCRIPTIVE DATA

Plant no.	Generating capacity (MW)	Coal firing rate (MM Btu/hour)	Applicable SO_2 regulations (lb SO_2/MM Btu)	Plant age (years)
1	400	3730	1.2	1
2	150	1440	1.8	10
3	600	Boiler 1-1190	1.8	10
		Boiler 2-2490	1.8	10
		Boiler 3-3280	1.8	10
		6960		

All five boilers are designed to burn the locally available coal with the quality and washability characteristics indicated in Table 4-2.

Three additional coal supplies were incorporated in the model to provide maximum flexibility in the control options. These added supplies represent the three general types of low sulfur coals. These three additional sources are the same as those used for the one plant scenario (see Table 3-1).

Table 4-2. QUALITY AND WASHABILITY CHARACTERISTICS OF COAL SUPPLIES

MINE SOURCE	Type of coal	Btu recovery at cleaning plant, %	Gross heating value Btu/lb	Sulfur content, lb SO_2/MM Btu	Ash content %	At mine cost,[b] $/MM Btu	Transportation cost $/MM Btu
A	Eastern low sulfur	NA	12,500	1.28	12.0	1.60	0.28
B	Western low sulfur, low Btu	NA	8,150	1.23	8.0	0.42	0.92
C	Western low sulfur, high Btu	NA	12,300	1.30	13.0	0.97	0.41
D	Midwestern coal (raw)	NA	12,074	6.96	18.[illegible]	0.70	0.09
	o OPTION A CLEANING Float 1.30	51	13,777	3.68	4.70	NA	0.08
	Sink 1.30-float 1.9	48	11,359	8.06	17.93	NA	0.09
	Sink 1.90	1	2,390	121.0	79.1	NA	0.43
	o OPTION B CLEANING Float 1.40	78	13,268	4.43	7.20	NA	0.08
	Sink 1.40-float 1.9	21	10,250	10.92	24.18	NA	0.09
	Sink 1.90	1	2,390	121.0	79.1	NA	0.43
	o OPTION C CLEANING Float 1.60	86	12,924	5.47	9.29	NA	0.08
	Sink 1.60-float 1.9	13	10,224	7.99	26.0	NA	0.09
	Sink 1.90	1	2,390	121.0	79.1	NA	0.43

The transporation costs are different due to the differences in the two networks. The fourth coal supply for each scenario is coal local to that particular network and thus the two have different characteristics.

Due to the small network fuel demand, it is assumed that there are no mine production constraints on any of these supplies. Purchased power was provided whenever necessary at a rate of $3.00/MM Btu which is roughly equivalent to 30 mill/kWh for a typical boiler with a heat rate of 10,000 Btu per KWh.

Due to the small plant sizes, the physical coal cleaning plant generally was smaller than 200 tons per hour which is the minimum size limit of the cost estimation models. Since it is unlikely that a plant smaller than 200 tons per hour would be built, the capital and annualized costs have been calculated based on this 200 tons per hour minimum size. It is assumed that excess production is sold to other utilities at cost.

4.1.1 Base Case Definition

To measure the potential benefit of combined strategy control, it is necessary to estimate costs of the present non-optimized network. For this three plant scenario the base case simulates an actual existing power plant system.

Prior to 1975 the company operated two plants with a combined generating capacity of 759 MW. The total power generating costs using local coal were estimated at 14.7 mills per kWh based on the cost factors shown in Table 4-3. The promulgation of an SO_2 regulation of 1.8 lb SO_2/MM Btu resulted in fuel switching to a high rank, western low sulfur coal. At the lower fuel sulfur levels, modification of the electrostatic precipitator was necessary to maintain particulate control efficiency. Average network cost increased

Table 4-3. ESTIMATED ANNUALIZED COST DATA,

$/MM Btu

		1975	1980
1.	Coal Costs		
	A. Eastern low sulfur coal	1.15	1.60
	B. Western low sulfur, low rank coal	0.30	0.42
	C. Western low sulfur, high rank coal	0.70	0.97
	D. Midwestern coal[a]	0.70	0.70
2.	Transportation Costs		
	Eastern low sulfur coal	0.20	0.28
	Western low sulfur, low rank coal	0.66	0.92
	Western low sulfur, high rank coal	0.30	0.41
	Midwestern coal (Raw)[b]	0.07	0.09
3.	Flue Gas Desulfurization Costs		
	Plant 1	0.43	0.60
	Plant 2	NA	0.82
	Plant 3	NA	0.53
4.	Electrostatic Precipitation Costs[c]		
	Plant 1	NA	NA
	Plant 2	0.046	0.065
	Plant 3 Boiler 1	0.090	0.130
	Boiler 2	0.046	0.065
	Boiler 3	0.090	0.130

[a]Fixed price, long term contract assumed.

[b]For cleaned coals.

[c]Depending on fuel quantity.

to 18.2 mills per kWh due to the use of low sulfur coal and to the ESP modification. In 1975 a new power plant went on-line. This plant was subject to Federal Standards of Performance and a flue gas desulfurization system was necessary. None of the assumed coal supplies had sulfur contents lower than the 1.2 lb SO_2/MM Btu. The FGD system increased average network power production costs to 18.5 mills/kWh. This annualized cost represents the base case for 1975 conditions. The base case is illustrated in Figure 4-1.

4.1.2 Combined Strategy Derived by Linear Programming Approach

The "optimum" strategy determined by the LP model is illustrated in Figure 4-2. This strategy is limited only to the extent that each plant must have a load factor between 40 and 80 percent. The strategy uses flue gas scrubbers on all three boilers of plant 3 and a 100 ton per hour coal cleaning plant. Incremental capital costs are 36.5 million, and the network average annualized cost is 19.6 mills/kWh (1980 cost factors). The annualized costs are 11 percent lower than the equivalent base case cost of 21.9 mills/kWh as listed in Table 4-4. Without the load factor constraints it is probable that the annualized costs could have been reduced further. The LP solution suggests that with some moderate capital expense a significant reduction in annualized costs can be achieved.

The sensitivity of the LP results to rising fuel costs and changing SO_2 regulations have been evaluated. The purpose is to determine if annualized costs continue to be lower than the base case and if any unnecessary capital costs would have been spent. In certain cases the LP results have been modified slightly to minimize capital costs.

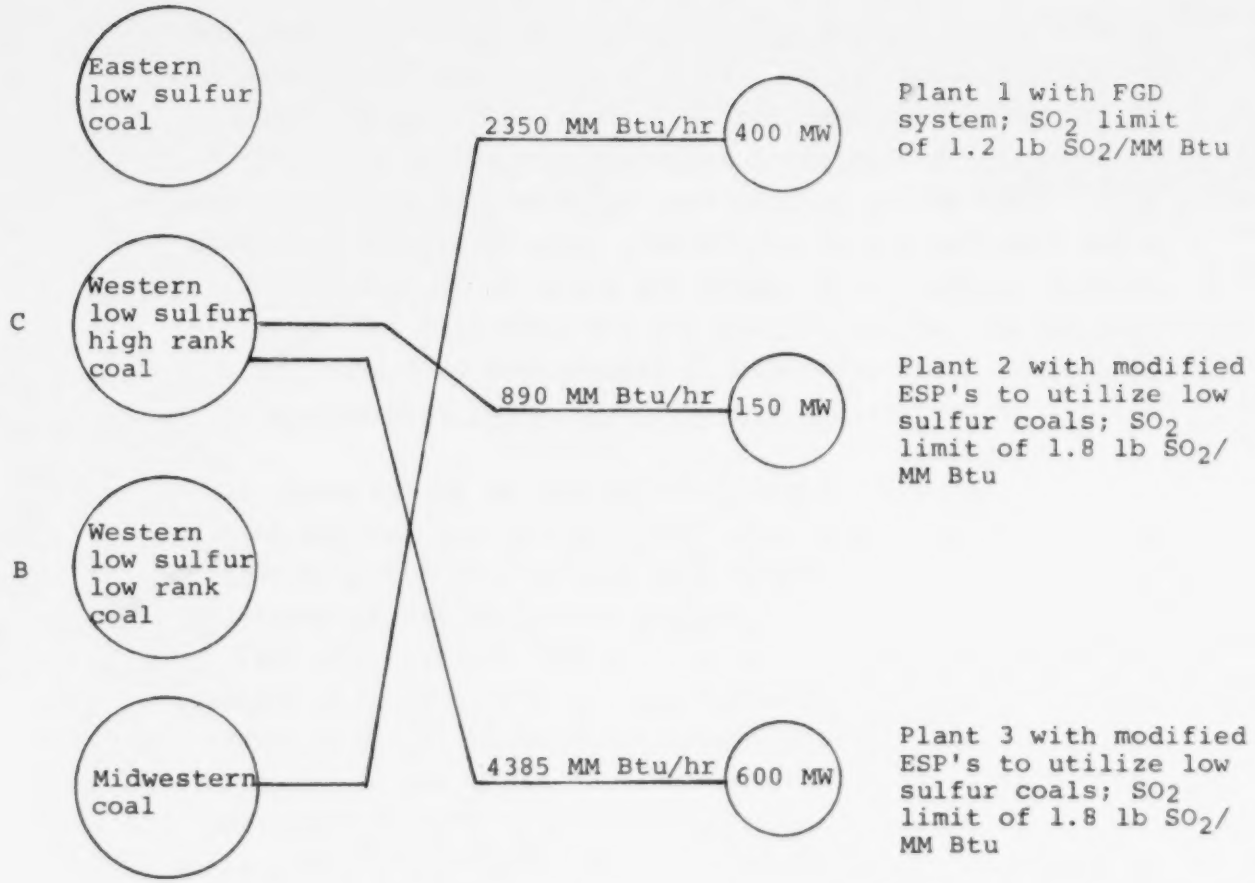
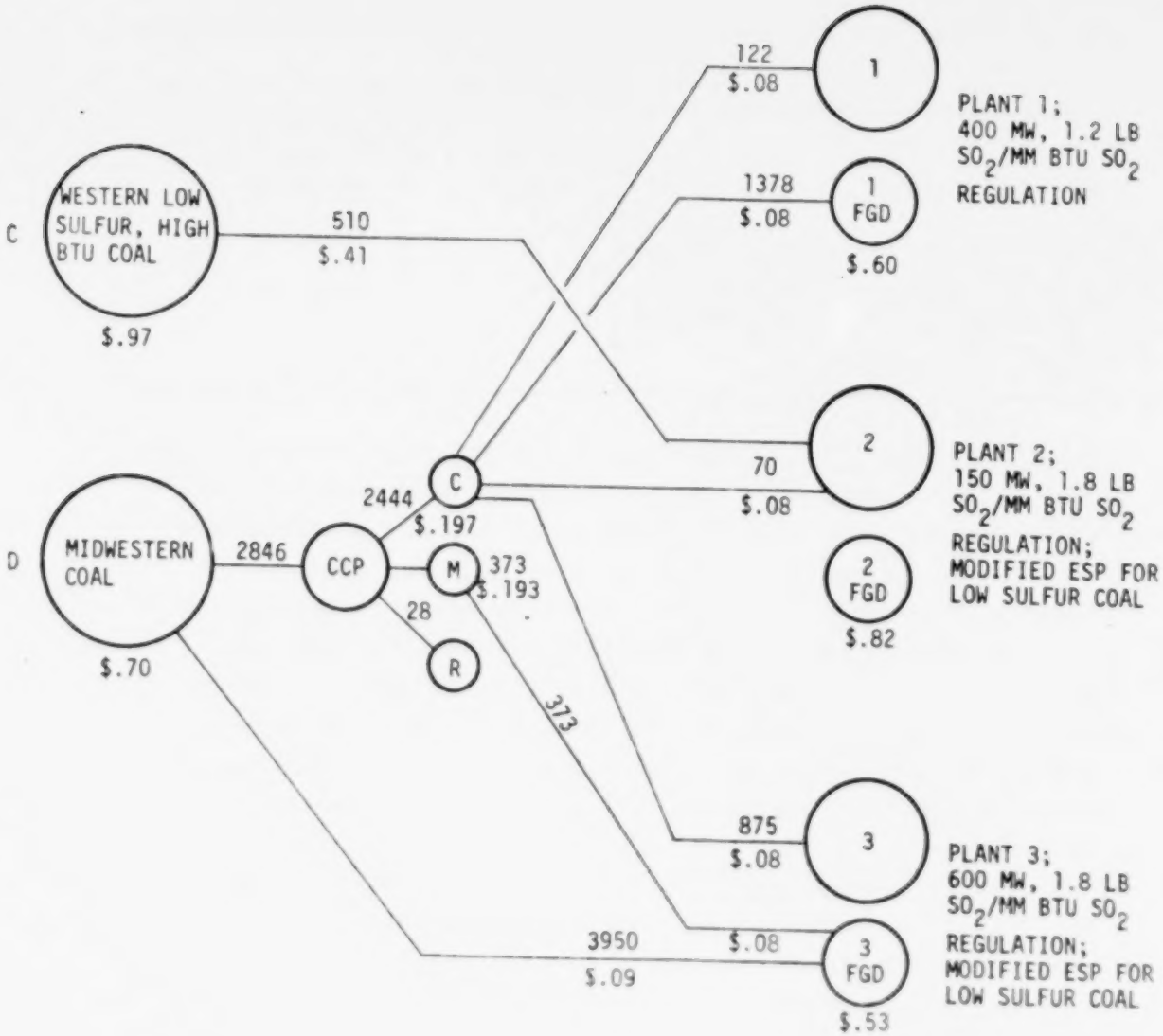

Eastern low sulfur coal
Western low sulfur high rank coal
C
Western low sulfur low rank coal
B
Midwestern coal
2350 MM Btu/hr
400 MW
890 MM Btu/hr
150 MW
4385 MM Btu/hr
600 MW
Plant 1 with FGD system; SO_2 limit of 1.2 lb SO_2/MM Btu
Plant 2 with modified ESP's to utilize low sulfur coals; SO_2 limit of 1.8 lb SO_2/ MM Btu
Plant 3 with modified ESP's to utilize low sulfur coals; SO_2 limit of 1.8 lb SO_2/ MM Btu

Figure 4-1. Base case; 63% LOAD
(Non optimized)



NOTE: coal flows shown as MM Btu/hour with network at 63 percent load.

Figure 4-2. LP results using combined strategy

Table 4-4. CAPITAL AND ANNUALIZED COSTS FOR THE BASE CASE (NON LP OPTIMIZED)

	Incremental capital cost	Annualized cost
	(MM)	(mills/kWh)
Base case 1975	36.5[a]	18.5
1980 - no change	-	21.9
1980 - All regs to 1.8 lb SO_2/MM Btu	-	21.9
1980 - higher coal cost	-	26.0

4.1.2.1 Higher Coal Costs - It is logical that costs of all coal supplies will continue to increase. For this analysis it is assumed that 1980 coal costs for the low sulfur coals increase 50 percent and that the cost of local coal increases 25 percent. Western low sulfur coals in particular have experienced more rapid price increases than the low quality coal supplies. This uneven rate of fuel cost escalation should favor use of the combined strategy alternative identified earlier. Three coal cleaning plant operations have been included in order to expand the scope of the analysis.

The results of the LP solution are presented in Table 4-5. The unmodified strategy utilizes new FGD systems at plants 2 and 3 and a coal cleaning plant between 60 and 125 tons per hour depending on the cleaning option. The annualized costs for all three coal cleaning options are approximately 30 percent lower than the base case (see Table 4-5.

[a] Due to application of SO_2 regulation and the use of low sulfur western coal.

Table 4-5. COMPARISON OF LP MODEL RESULTS AND BASE CASE COSTS FOR HIGHER COAL COSTS

	Standard Calculations		Capital Cost Adjustment	
	Incremental capital cost (MM)	Annualized cost (mills/kWh)	Incremental capital cost (MM)	Annualized cost (mills/kWh)
Base case	-	26.00	-	26.00
LP Models				
Coal cleaning to float 1.9	50.20	20.96	38.62	20.99
Coal cleaning to float 1.4	49.86	20.84	38.68	20.86
Coal cleaning to float 1.3	51.04	21.00	40.45	21.14

A slight adjustment of the LP solution can substantially improve the capital cost requirements. Low sulfur, high rank western coal has been substituted for the local high sulfur coal at plant 2, thereby eliminating the small FGD system at that plant. The annualized cost difference between the optimum and the capital cost adjusted strategies is insignificant.

The results indicate the optimal combined strategy would be more economical than the base case if the coal costs increased as assumed. A different result would occur in the improbable event that the high sulfur coal prices increased faster than that of the low sulfur coals.

4.1.2.2 Relaxation of SO_2 Standards - The relaxation of SO_2 regulations in one or more of the plants is improbable;

nevertheless, this could make a previously attractive combined strategy approach uneconomical. To test the impact of a regulatory change on LP solution costs, the LP solution and base case costs have been recalculated assuming the regulatory requirement on plant 1 changes from 1.2 lb SO_2/MM Btu to 1.8 lb SO_2/MM Btu. While this appears to be only a modest relaxation of the standard, it allows use of low sulfur coals at plant 1 without any coal cleaning or flue gas scrubbing.

The results are presented in Table 4-6. It is apparent that the LP solution appears relatively stable to slight relaxation of the SO_2 standards. If the regulation limits were increased to 3 or 4 lb SO_2/MM Btu, the FGD system at plant 3 would not be economical.

4.2 LARGE NETWORK EXAMPLE

A seven plant network with a combined generating capacity of 12,970 MW was used to represent a large power plant system. The plants and coal supplies used in this scenario are provided in Table 4-7. It is assumed that all boilers are designed to burn Eastern Midwest Region coals. Six typical coal sources with various cleanability properties were selected along with the three low sulfur coal supplies used in the small network scenario. Coal quality and cost data are presented in Table 4-8.

Due to the large network fuel demand, it has been assumed that each coal source can supply no more than 20 percent of the total fuel demand. Coal cleaning plants have been allowed for Eastern Midwest coal sources numbered 1 through 5, but not for mine no. 6, due to the low sulfur content. Cleanability data are based on tests of TVA supplied coal samples. Purchased power was provided whenever necessary at a rate of $3.00/MM Btu, which is roughly

Table 4-6. COMPARISON OF LP MODEL RESULTS AND BASE CASE COSTS WITH ALL SO_2 REGULATIONS AT 1.8 lb SO_2/MM Btu

	Incremental capital cost (MM)	Annualized Cost (mills/kWh)
Base Case	-	21.9
LP Models		
Minimum cleaning	39.3	19.5
Moderate cleaning	41.0	19.4
Intense cleaning	40.5	19.5

Table 4-7. LARGE NETWORK DESCRIPTIVE DATA

Plant number	Utility[a] company	Generating capacity (MW)	Coal firing rate (MM Btu/hr)	Applicable SO_2 regulation (lb SO_2/MM Btu)	Plant age (years)
1	1	1750	1.75×10^4	1.2	10
2	1	2560	2.56×10^4	5.2	10
3	1	2600	2.60×10^4	5.0	10
4	1	990	9.90×10^3	4.0	10
5	1	1700	1.70×10^4	1.2	10
6	2	1400	1.40×10^4	4.0	10
7	2	1980	1.98×10^4	1.2	10

[a]The plants are arbitrarily assigned to two different utility companies in order to consider the problem of suboptimization of the individual networks and to compare these results with those obtained by optimization of the total system of both networks.

Table 4-8. QUALITY AND COSTS OF COAL SUPPLIES

Type of coal	Gross heating value (Btu/lb)	Sulfur content (lb SO_2/MM Btu)	Ash content (%)	At mine cost ($/MM Btu)[a]
Eastern low sulfur	12,500	1.28	12.0	1.60
Western low sulfur, low Btu	8,150	1.23	8.0	0.42
Western low sulfur, high Btu	12,300	1.30	13.0	0.97
Eastern Midwest No. 1	12,074	6.96	18.	0.70
Eastern Midwest No. 2	10,955	5.64	20.9	0.70
Eastern Midwest No. 3	10,502	8.10	18.1	0.70
Eastern Midwest No. 4	11,502	6.21	17.3	0.70
Eastern Midwest No. 5	10,971	7.72	21.9	0.70
Eastern Midwest No. 6	11,169	1.71	15.0	1.30

[a]The costs used in this report are not based on actual coal contracts.

equivalent to 30 mills/kWh for a typical boiler with a heat rate of 10,000 Btu per kWh.

4.2.1 Base Case Definition

The estimated costs from the LP solution are compared with those for a non-optimized system. It has been assumed that all plants presently utilize one or more of the Eastern Midwest Region coals. Fuel distribution is allowed, however, the assumption of equal costs for all high sulfur midwestern coals reduces the importance of redistribution. The base case involves the addition of FGD systems, wherever necessary, in order to comply with SO_2 emission regulations. Coal cleaning is not utilized in the base case calculations.

The capital and annualized costs for the base case control approach are summarized in Table 4-9. All costs are escalated by a factor of 1.4 to approximate 1980 costs.

4.2.2 Linear Program Derived Combined Strategy

The "optimum" strategy has been identified for each power plant network separately and for the total seven plant network. As indicated in Table 4-9, there is a 4.5 percent reduction in the complete network annualized costs and a 20 percent reduction in capital costs. This results from a decrease in the number of FGD units and from the use of coal cleaning on all major coal supplies. While the 4.5 percent decrease in annualized cost does not appear to be large, it represents a 30 percent reduction in the annualized SO_2 control cost (FGDs, CCPs and ESPs). These results for the seven plant system suggest that the LP model is useful in identifying optional SO_2 control strategies for a large, complex power plant-fuel supply system.

The LP models for the individual five- and two-plant networks indicate large differences in the capital and annualized costs. As shown in Figure 4-3, the strategy for

Table 4-9. CAPITAL AND ANNUALIZED COSTS FOR LP COMBINED STRATEGY

	Base case	Combined strategy	Combined strategy with less restrictive SO_2 limits at plants 1, 5, and 7[a]	Combined strategy with more restrictive SO_2 limits at plants 2 and 3[b]
Capital Costs (10^6\$)				
Network 1	N.D.	83.90	N.D.	N.D.
Network 2	N.D.	91.30	N.D.	N.D.
Total system	184.0	141.40	122.8	191.5
Annualized Costs (mills/kWh)				
Network 1	N.D.	15.47	N.D.	N.D.
Network 2	N.D.	17.50	N.D.	N.D.
Total system	16.48	15.77	15.52	16.21

N.D. = Not determined.

[a] SO_2 regulations changed from 1.2 to 1.8 lb SO_2/MM Btu.

[b] SO_2 regulations changed from 5.2 at plant 2 and 5.0 at plant 3 to 4.0 lb SO_2/MM Btu at each plant.

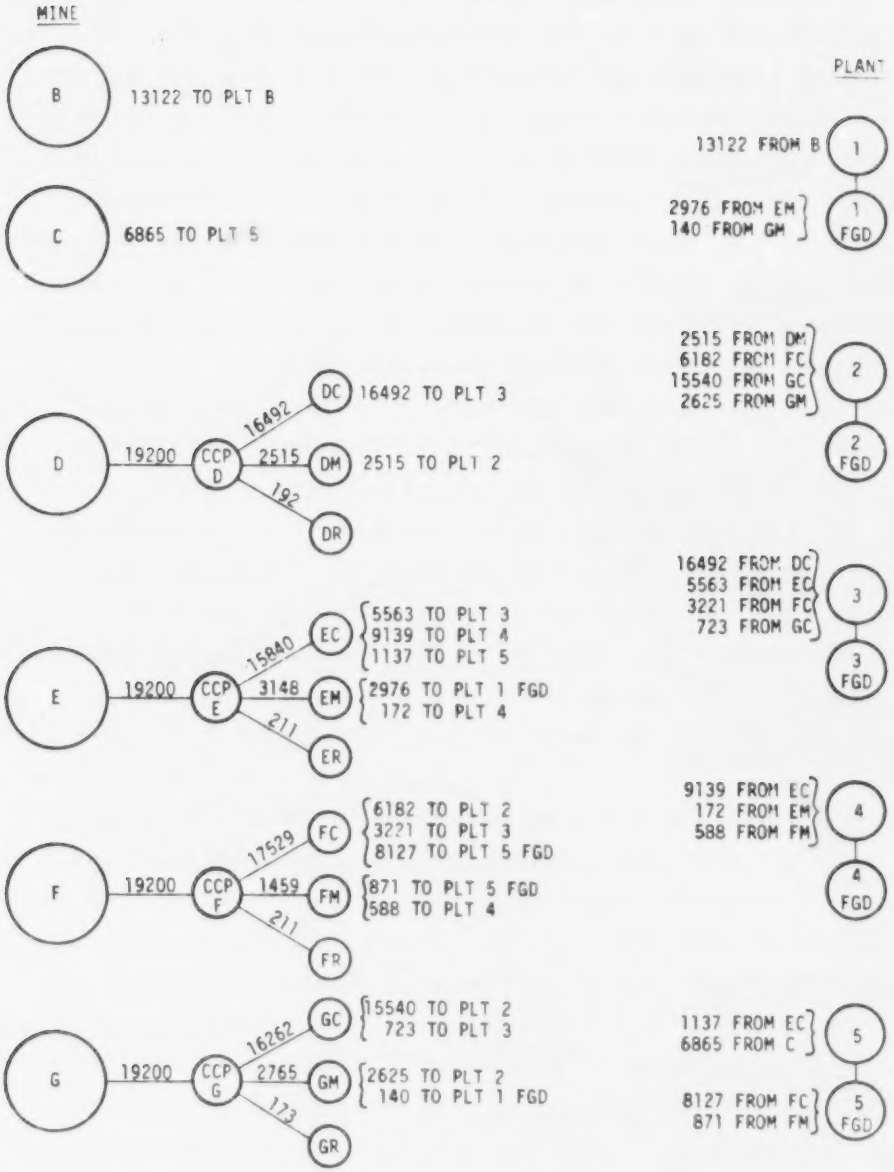


Figure 4-3. LP results or LP coal distribution for network 1, 5 plants. Flows are in MM Btu/hour.

network 1 involves cleaning four of the Eastern Midwest coals. Extensive fuel redistribution is done to reduce loads on the plants subject to the most stringent SO_2 regulations. While the LP program indicated that FGD would still be the most economical control technique for the "peaking units", use of FGD for such service was not considered realistic. Therefore, low sulfur western (high Btu) was substituted for FGD's at a slight cost penalty. This substantially reduced the capital cost impact of the LP strategy. The strategy for network 1 involves FGD systems at two plants and extensive cleaning of three Eastern Midwest coals.

Despite the much smaller size of network 2 compared with network 1 (3380 MW versus 9590 MW) the capital costs for SO_2 compliance systems at network 2 exceed those for network 1. Consequently, the annualized cost for network 2 is 13 percent higher than for network 1. The high cost for SO_2 control at network 2 is primarily due to the lower average sulfur limits. The weighted average sulfur dioxide regulation for network 2 is only 2.35 lb/MM Btu compared with 3.60 lb/MM Btu for network 1. See Figure 4-4 for details.

The LP solution for the complete seven plant network (see Figure 4-5) yields substantially lower capital costs than those for either the base case or the LP solutions for the individual networks. This economy results from more efficient fuel redistribution which allows deletion of an FGD system on plant 6. Savings also result from the sharing of coal cleaning plants. With the LP approach, both utility companies in this hypothetical problem should realize a reduction in capital costs for SO_2 control. Unfortunately, the changes in annualized cost are not equitable. As shown in Table 4-9, the total cost for network 2 decreases sub-

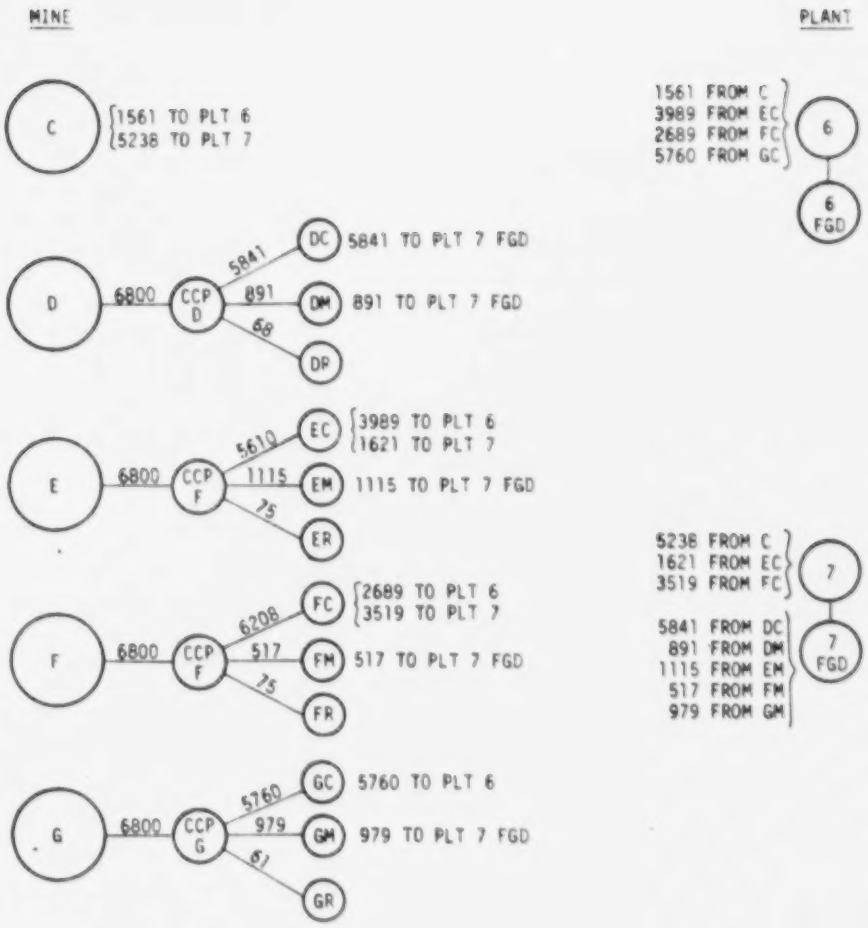


Figure 4-4. LP results for network 2, 2 plants
Flows are in MM Btu/hour.

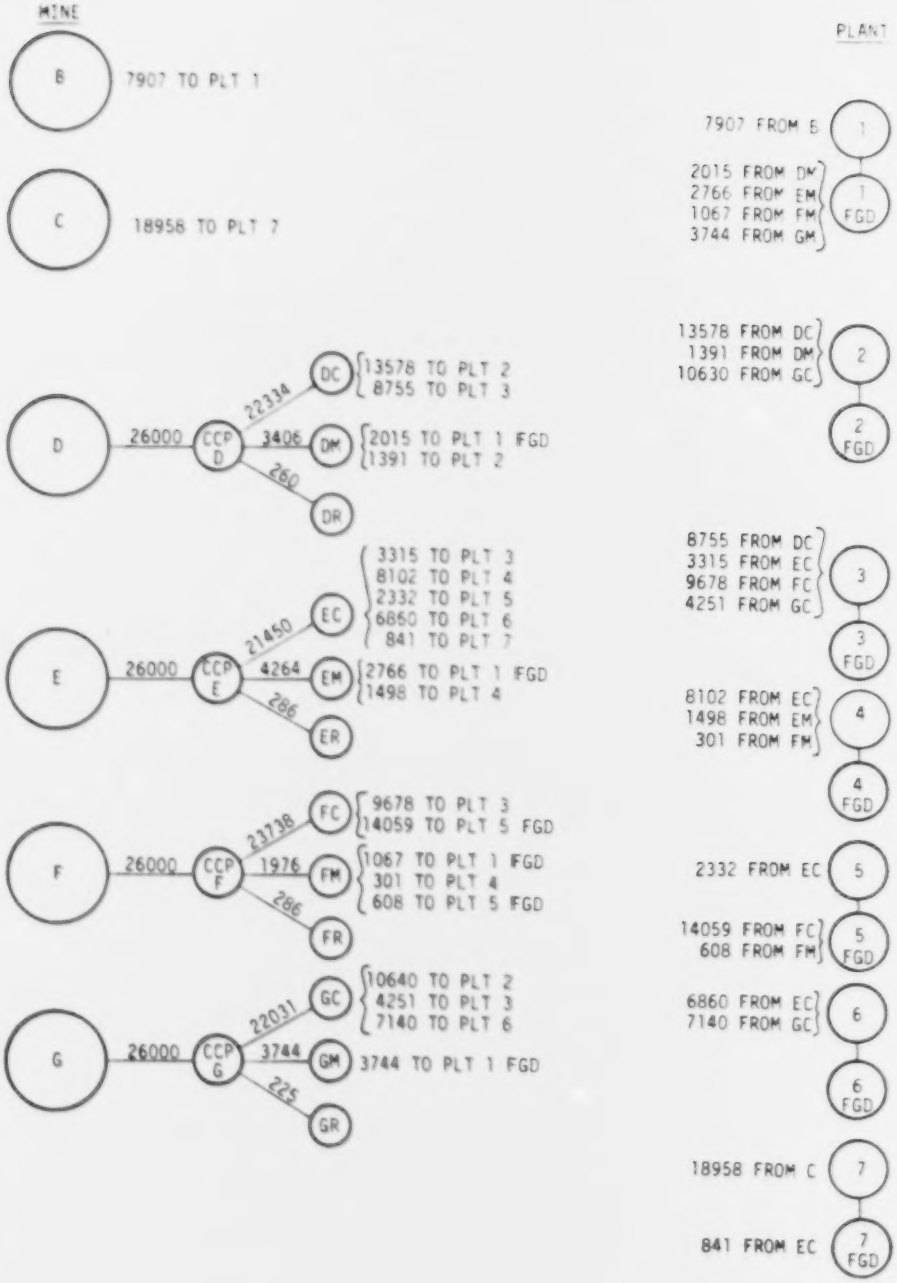


Figure 4-5. LP results for combined network.
Flows are in MM Btu/hour.

stantially (10%), while costs for network 1 increase slightly (2%).

The LP results for the complete seven plant network are relatively insensitive to minor changes in SO_2 regulatory requirements. A relaxation of the 1.2 lb SO_2/MM Btu limits at plants 1, 5, and 7 would not change the basic control approach discussed above. An FGD would continue to be necessary at plant 7. The only change would be decreased dependence on the coal cleaning plants, one of which could be eliminated entirely. Due to the deletion of the CCP at mine 1 (Eastern Midwest Region) and a slight size reduction at the other CCPs, there is a $18.6 million capital cost decrease. A 2 percent reduction in annualized cost is possible with the less stringent regulations. A tighter constraint (4.0 lb SO_2/MM Btu) on plants 2 and 3, which presently are subject to 5.2 and 5.0 lb SO_2/MM Btu, respectively, has a contrary result. With this change, new FGD systems are required at plants 2 and 6. The capital costs for the entire system increase $50.1 million, due primarily to this regulation change. It is uncertain whether network 2 could justify its share of this increase, which was necessitated by regulatory changes applying only to network 1. Despite this potential legal problem, the average annualized cost remains below that for the non-optimized base case.

While the application of LP derived strategies appears to have considerable potential in reducing SO_2 compliance costs for large networks or combinations of moderately sized networks, certain possible legal problems may complicate acceptance by regulatory commissions. As discussed above, there can be situations in which the average power production cost increase slightly for one member while it

decreases for another. Furthermore, capital cost may not be equitably distributed among the member utilities. Both problems would complicate rate determination for each separate utility.

5.0 APPLICATION OF LINEAR PROGRAMMING TECHNIQUES

The general procedures necessary to prepare the LP program input data and to adjust nonlinear cost factors are presented in this section. The purpose is to assist potential users in the development of LP models specific to actual power plant networks. It is assumed that source operators have accurate estimates of fuel costs, boiler operation and maintenance costs, and purchased power costs. Therefore, these three cost components are not discussed in detail. Emphasis is placed on estimating the performance and costs of flue gas desulfurization systems, coal cleaning plants, and electrostatic precipitators. A set of typical cost estimates is provided for all three systems[a]. Use of such generalized values is a defensible shortcut since experience with the multiple plant scenarios indicates that the LP solution is much more sensitive to fuel cost and quality than to FGD, CCP, or ESP costs. Relative to fuel prices, the equipment associated costs vary over a limited range.

The FGD, CCP and ESP cost coefficients are inherently nonlinear functions of the plant size. A heuristic approach is provided to insure that the input cost coefficients for these three components and the cost implied by the plant size of the LP solution are compatible.

This section stops short of a complete user's manual. Guidance is provided with respect to compiling input data matrices and to managing nonlinear functions. The user should consult the programming manual of the type of LP

[a]It should be noted that the generalized results were developed using the same computerized cost models used in the multiple plant scenarios; nevertheless, cost values may differ slightly due to NETWORK specific assumptions employed.

program selected (e.g. MPS, FMPS) for details concerning the program set-up and operation.

5.1 EQUIPMENT COST AND PERFORMANCE ESTIMATES

The engineering and cost data generally needed to estimate the LP input data of FGD, ESP and CCP systems are discussed in the following three subsections. The user has the option of utilizing his own cost estimating procedures for this data or the generalized results provided which are based on PEDCo computerized procedures. Standard cost factors used in all three programs are identified in Table 5-1.

5.1.1 Coal Washability and Cleaning Plant Costs

5.1.1.1 Washability - Coal washability characteristics are major variables in the cost optimization study. Accurate prediction of clean stream and middling stream coal quality is necessary in the derivation of representative LP models. The data requirements for evaluating coal washability potential are identified by reviewing typical coal cleaning plant design.

Raw coal received at the CCP is first subjected to one or two stage crushing with subsequent size segregation into coarse, intermediate, and fine size fractions. Typical coal sizes in these three groups are respectively 1 1/2" by 3/8", minus 3/8" × 35 mesh, and minus 35 mesh. These three size fractions are treated separately in order to achieve reductions in ash and pyrites. All of the techniques used in the coarse and intermediate size processing circuits utilize differences in specific gravity of the carbonaceous coal (0.9 to 1.3) and the ash (2.0 to 2.3) and pyrites sulfur (2.0 to 2.3). A simplified flowsheet is provided in Figure 5.1. The coarse fraction is processed in heavy medium vessels or cyclones while the intermediate fraction is

Table 5-1. GENERAL COST FACTORS

Cost Component	Percentage of total direct cost
Capital Costs	
Interest during construction	8
Contractor fees	10
Engineering	6
Free agent	1.25
Off Site	3
Taxes	1.50
Spares	1
Shakedown	3
Contingency	20% (direct & indirect)
Annualized Costs	
Electricity	30 mills/kWh
Water	3 ¢/M gal
Operating labor	
Direct labor	$8.50/manhour
Supervision	15% direct labor
Maintenance	
Labor and materials	4% of fixed investment
Supplies	15% of labor and materials
Overhead	
Plant	50% of operation and maintenance
Payroll	20% of operating labor
Fixed Costs	
Depreciation	5% fixed investment
Interim replacement	0.35% fixed investment
Insurance	0.30% fixed investment
Taxes	4.0% fixed investment
Capital costs	9.0% fixed investment

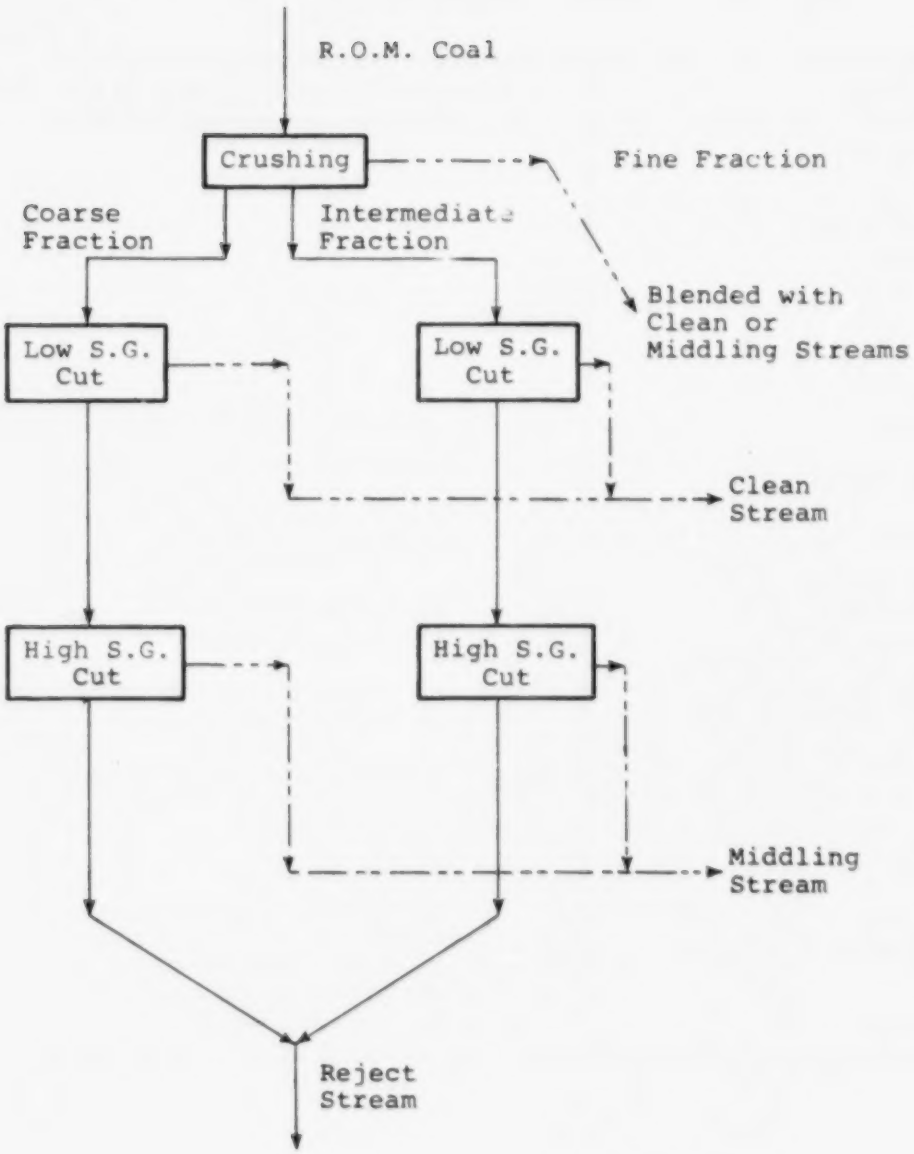


Figure 5-1. Simplified coal cleaning plant flowsheet

treated on concentration tables. In both circuits the new raw coal undergoes low specific gravity treatment which splits into clean and middling-refuse streams. A second treatment at higher specific gravity completes separation of the middling and refuse streams. The plant operator has considerable discretion in selecting the specific gravity cut ranges in both stages. In this way it is possible to partially control the coal quantity and quality in each of the three output streams. It should be noted that the fine fraction is not amenable to conventional cleaning techniques based on specific gravity. While such material can be cleaned using froth flotation which takes advantage of differing surface properties, generally this material is dried and reblended with the clean or middling streams. A considerably more extensive discussion of CCP design and operation is available in reference 1.

Based on typical operating practice it is apparent that the following engineering data is necessary to estimate multistream coal quality:

1. Coal grindability (weight distribution of raw coal into three size categories).

2. Float-sink data applicable to coarse and intermediate size ranges, including the following variables:
   a. weight distribution
   b. Btu distribution
   c. total sulfur distribution
   d. ash distribution.

3. Specific gravity cut values for each stage of coarse and intermediate circuits.

4. Deposition of fine fractions.

The first two variables are a function of the coal supply. Due to the substantial variability of these wash-

ability characteristics, actual test data for this anticipated coal supply must be available. Even with actual mine samples some error is inevitable since the separation efficiencies of commercial cleaning plant equipment cannot be readily taken into account. Also it is difficult to obtain a fully representative sample of the unmined coal supply. Nevertheless, with the data identified above and with simple material balance calculations, it is possible to approximate the characteristics of output coal streams.

In the multiplant scenarios, actual data from some Midwest Region mines were used in conjunction with three sets of assumed specific gravity cuts. The make-up of the clean, middling, and reject streams for these three cleaning strategies is identified in Table 5-2.

Table 5-2. COAL CLEANING STRATEGIES

Coal cleaning strategy	Coal Streams		
	Clean	Middling	Reject
A	float 1.30	(sink 1.30-float 1.90) + Fines (dried)	sink 1.90
B	float 1.40	(sink 1.40-float 1.90) + Fines (dried)	sink 1.90
C	float 1.60	(sink 1.60-float 1.90 + Fines (dried)	sink 1.90

The three strategies listed above are considered representative of over 150 logical operating conditions. Strategy C would primarily accomplish some ash reduction while strategy A represents maximum cleaning for ash and pyrite removal. Economical separation at a specific gravity of 1.3 has not been commercially proven.

The three cleaning strategies of Table 5-2 are recommended as a starting point for the evaluation of LP derived strategies. Ultimately the user will want to optimize the CCP plant design and rerun the corrected models.

5.1.1.2 Cleaning Plant Costs - The estimation of coal cleaning plants costs is a complex problem involving the selection and size of all major plant components. It is recognized that some potential users will not desire to perform independent cost analyses based on the engineering variables identified in Section 5.1.1.1. Accordingly, some generalized results obtained using the PEDCo computerized physical coal cleaning plants model are provided. This section also serves to document the assumptions employed in the scenarios discussed in Section 4. A more detailed discussion of the CCP cost model is available in reference 1.

The size ranges considered vary from 200 tons/hour (assumed economical minimum) to 3000 tons/hour. The capacity factor is assumed to average 60% for 6000 hours of operation per year. An escalation factor of 1.4 has been used to adjust cost to a 1980 basis. It is assumed that the cleaning plant is located in the general vicinity of the mine.

The resulting annualized and capital costs for a typical coal cleaning plant are shown in Figure 5-2. These costs correspond to a plant between 200 and 1400 tons per hour with product streams equivalent to strategy C (see Table 5-2). Costs did not vary substantially for the 3 cleaning options.

The cost model has been developed based on extensive analysis of cost data provided by major vendors of coal cleaning plant equipment. While the results generally

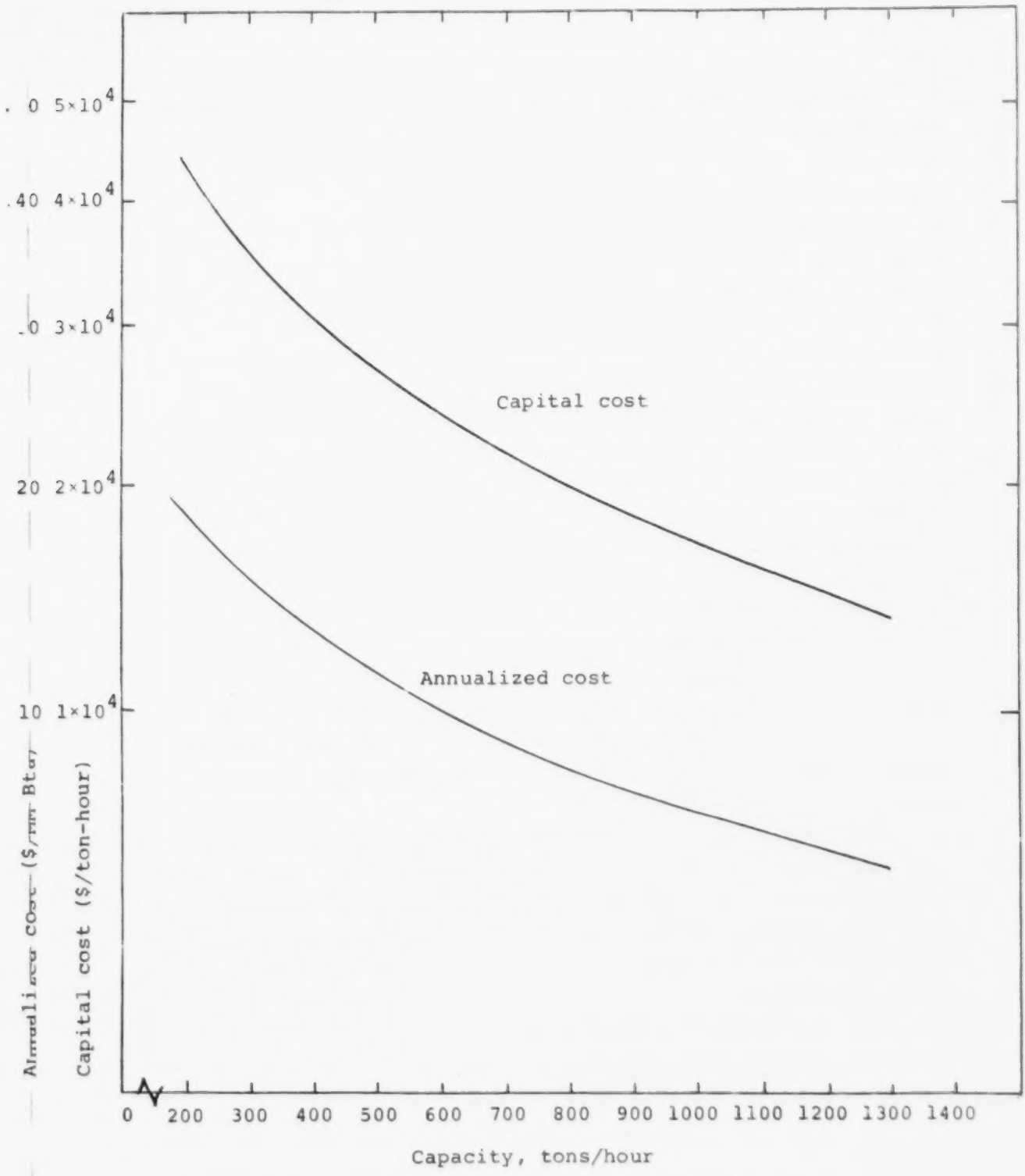


Figure 5-2. Costs for a typical coal cleaning plant

correspond to within ± 40% of reported costs for coal cleaning plants, a detailed evaluation of the accuracy of the model is not included in this study.

The user has the option of allocating the costs to three output coal streams as appropriate. In this project such costs have been assigned to the clean and middling streams strictly on a Btu basis. The reject stream was assigned no cost other than a transportation cost from CCP to the utility plant.

5.1.2 Flue Gas Desulfurization Costs

The role of FGD systems is to provide for compliance with SO_2 emission regulations at plants having excessive quantities of sulfur in the fuel. This fuel may be uncleaned coal or a blend of coals that include streams from one or more physical coal cleaning plants. Since the SO_2 removal efficiency of FGD systems is typically in the range of 75 to 90 percent efficiency (85 percent was used for this project), the average sulfur content of the input fuel can be 4 to 10 times higher than the applicable SO_2 limit. Depending on the quality and cleanability of the fuel supplies available, this capability to use higher sulfur coals represents a possible fuel cost savings. These savings are offset by FGD annualized costs ranging from 4 to 8 mills/kWh.

5.1.2.1. Variables Affecting FGD Costs - A variety of process and site specific factors can have a large influence on the capital and annualized costs of FGD systems. Capital costs can vary from \$34 to \$116/kW[4] (installed basis - 1975 dollars) while the annualized cost can vary from 4 to 8 mills/kWh. The factors responsible for this variability partially determine whether FGD is economically competitve with the relatively expensive low sulfur coals. Factors of

importance include plant size, plant remaining life, average fuel sulfur content, maximum allowable SO_2 emission rate, waste disposal costs, retrofit complexity, energy consumption, and replacement power requirements. Costs for particulate control are not considered in the FGD models used in this project.

System Capacity - Redundancy requirements impose a strong scale factor on the capital costs of an FGD system.[b] A system composed of two 150 MW capacity units could require one additional redundant train, whereas a system composed of six 150 MW capacity units would probably require two redundant trains. Obviously the relative cost in the smaller network is larger than for the 900 MW system.

In addition to these redundancy requirements, there are also normal economies of scale involved where a scrubber module less than 150 MW is necessary. A 50 MW FGD system has been used as the minimum since the capital costs on a $/kW basis increase exponentially below this size.

Plant Remaining Life - Flue gas desulfurization systems are not generally installed on boilers with a limited remaining life since the costs cannot be amortized at an acceptable rate. Boilers with less than 10 years serviceable life remaining can have annualized FGD costs substantially greater than new boilers with expected life of 35 to 40 years. Furthermore, old boilers tend to be swing loaded or restricted to peaking service due to the high cost per kWh. A plant remaining life of 20 years has been used in all model calculations for the present project.

Installation Status - Capital costs for a new system can be substantially lower than for retrofit FGD systems due to construction costs. Retrofit applications can involve extensive modifications of the existing site, non-optimal

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[b] An FGD system is considered as one or more trains each of which contains ducting, absorber, holding tank, agitators, recirculation pump(s), demistor, reheater, soot blowers, ducting shut-off valves, piping and controls.

system layout, increased construction labor, and longer construction periods. The potential impact of these problems is illustrated in Table 5-3.

Table 5-3. EFFECT OF RETROFIT DIFFICULTY ON FGD CAPITAL COST

	Capital cost increase, %
Large duct runs	4-7
Tight space	1-18
Delayed construction	5-15
New stack	6-20
Possible range (one or more retrofit problems)	

It has been assumed in the example of this study that retrofit costs for FGD systems in the hypothetical power plants are insignificant. LP model results for actual networks could be altered substantially in cases where retrofit of FGD systems is difficult.

Sludge Disposal - Waste disposal for nonregenerable FGD processes can have a major impact on both capital costs and operating costs. The costs depend on the sulfur and ash content of the coal, the rate of limestone use, moisture content of the sludge, and treatment processes.

The capital costs for sludge disposal vary from $3.5/kW to $10/kW depending on the location of the disposal area relative to the plant and on the need to stabilize the sludge for landfill. Operating costs can range from 0.2 to 1.5 mills per kWh depending primarily on the same two factors.

SO_2 Removal Requirements - The quantities of SO_2 which must be removed affect both the capital and operating costs. The

capital costs for limestone storage and feeding and for sludge treatment and disposal are a function of the removal requirements. The costs for most raw materials and utilities are also proportional to removal requirements. The impact on total annualized costs can be 1 to 2 mills per kWh.[4] Relatively inexpensive pond disposal has been used in the models for the present project.

5.1.2.2 Capital and Annualized Cost Estimates - Specific cost factors and design assumptions incorporated into the FGD cost estimation models are presented in Table 5-4. An escalation factor of 1.4 was used to adjust the cost to a 1980 basis. A limestone scrubbing system was used throughout this project.

The resulting annualized and capital costs for one of the plants are illustrated in Figure 5-3. These correspond to an FGD ranging in size from 50 to 500 MW equivalent capacity, with an inlet sulfur content of 7 lb SO_2/MM Btu and an outlet concentration of less than 1.8 lb SO_2/MM Btu. It was assumed that the power plant had a remaining life of 20 years and did not require extensive retrofit modifications. Ponding was assumed for sludge disposal. Costs for installations with somewhat different conditions vary as indicated in Table 5-5.

The cost estimates determined using the computer model have been compared with a survey of actual costs reported in an Edison Electric Institute study. The range in reported costs is in close agreement with the range predicted by the model.[4] The costs also agree within ± 20 percent (depending on retrofit assumptions) with the estimates of two vendors. Based on these comparisons, the FGD model used in this project is considered to be accurate to ± 20 percent for both annualized and capital costs.

Table 5-4. SPECIFIC COST FACTORS AND DESIGN ASSUMPTIONS USED IN FGD COST ESTIMATION MODELS

Design Assumptions	
1. Absorber	Two stage turbulent content absorber with Δp = 10 H_2O and L/G = 65 GPM/MACFM. Gas velocity of 10 FPS, Chevron entrainment separator of 2" Δp, 85% SO_2 removal efficiency.
2. Fan	Double inlet centrifugal fan with static pressure of 16" Δp.
3. Reheater	Indirect tubular reheater using low pressure steam to achieve ΔT of 50°F.
4. Limestone storage	Dead storage pile sized for 30 days capacity; live storage sized for 3 day capacity.
5. Waste disposal	Clarifiers used to concentrate effluent slurry from 15 to 30% solids. Following vacuum filtration to 60% solids fixation additives are added and the slurry is discarded in the sludge pond.
Cost Factors	
Limestone costs	$12/tons
Fixation chemicals	$2/ton
Utilities	
Electricity	30 mills/kWh
Water	3.0 ¢/M gal
Reheat steam	$0.76/MM Btu
Operating labor	
Direct labor	$8.50/manhour
Supervisor	15% of direct labor
Maintenance	
Labor and materials	4% of fixed investment
Supplies	15% of labor and materials
Overhead	
Plant	50% of operation and maintenance
Payroll	20% of operating labor
Fixed costs	
Depreciation	5.0%
Interim replacement	0.35%
Taxes	4.0%
Insurance	0.3%
Capital costs	9.0%

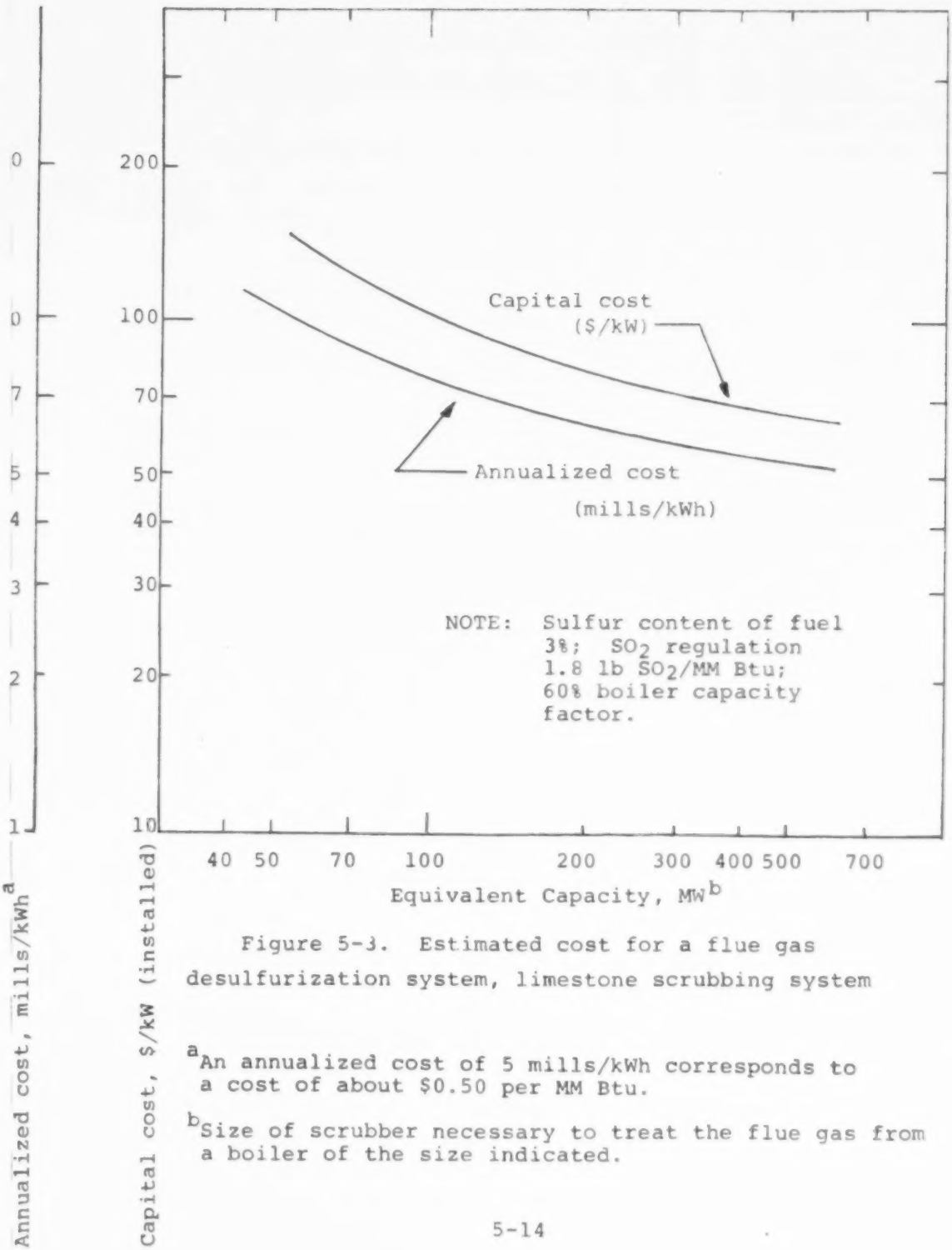

Figure 5-3. Estimated cost for a flue gas desulfurization system, limestone scrubbing system

[a]An annualized cost of 5 mills/kWh corresponds to a cost of about $0.50 per MM Btu.

[b]Size of scrubber necessary to treat the flue gas from a boiler of the size indicated.

Table 5-5. INFLUENCE OF PROCESS SPECIFIC AND SITE SPECIFIC FACTORS OF FGD COSTS

Factor	Typical capital cost impact, %	Typical annualized cost impact, %
1. SO_2 removal requirements	15-20	10-15
2. Installation status	10-40	10-20
3. System size	10-40	10-20
4. Waste Disposal	10-30	10-20
5. Plant remaining life	-	10-200

5.1.3 Electrostatic Precipitator Costs

The use of low sulfur coals in boilers originally designed for 2-4% sulfur coals can alter the collection efficiency of existing electrostatic precipitators. In the 300°F to 400°F range the low sulfur coal ash typically exhibits a low surface conductivity which adversely affects the precipitation rate parameter. The source operator has the choice of modifying the ESP to account for the resistivity problem or of using surface conditioning agents such as sulfuric acid vapor. The latter option is not considered to be commercially proven under all circumstances; therefore, ESP modification costs are provided. It should be noted that in those cases where conditioning is feasible, costs would be considerably lower than ESP modification costs.

5.1.3.1 Variables Affecting ESP Costs - The average sulfur content of the boiler coal stream is the principal variable

affecting costs. This value in conjunction with the flue gas temperature in the ESP determines the resistivity of the particulate to be collected. Other variables of importance include the gas flow rate, efficiency required, and retrofit difficulty.

5.1.3.2 Capital and Annualized Costs - Cost estimates are provided in Tables 5-6 and 5-7. The incremental cost for a specific size of system can be calculated by subtracting costs for the new sulfur content from that of the design sulfur content. These costs include an escalation factor of 1.4 to adjust to a 1980 basis.

5.2 POWER GENERATION COSTS

There are a variety of power generation costs which must be considered in the LP model in order to derive realistic costs. These cost components include coal costs, coal transportation costs, boiler operation and maintenance costs, and purchased power costs. Due to the hypothetical nature of the scenarios, only general estimates were used for such costs. It is assumed that potential users of LP models will have comprehensive, accurate data available for the specific network studied. Nevertheless, there is some advantage in discussing the procedures used in the previously described scenarios.

5.2.1 Coal Transportation Costs

The variables affecting fuel transportation cost (on a MM Btu basis) include the distance of transport, mode of travel, and the heating value. The values in Table 5-8 were used to approximate coal transport cost.

Table 5-6. CAPITAL COSTS OF ELECTROSTATIC PRECIPITATORS, 10^6

MW capacity of boiler controlled by ESP	Percent Sulfur in Fuel				
	3%	2.5%	2%	1.5%	1.0%
10	1.10	1.27	1.50	1.87	2.46
20	1.98	2.28	2.67	3.23	4.07
30	2.75	3.12	3.60	4.26	5.21
50	3.96	4.41	4.98	5.74	6.89
70	4.87	5.38	6.00	6.88	8.39
100	5.97	6.53	7.30	8.50	10.84
200	8.91	10.05	11.81	14.79	20.48
500	19.64	23.18	28.42	36.49	51.16

Table 5-7. ANNUALIZED COST FOR ELECTROSTATIC PRECIPITATORS, mills/kWh

MW capacity of boiler controlled by ESP	Percent Sulfur in Fuel				
	3%	2.5%	2%	1.5%	1.0%
10	2.67	3.00	3.45	4.18	5.34
20	2.20	2.49	2.88	3.42	4.26
30	1.97	2.21	2.52	2.96	3.60
50	1.66	1.84	2.07	2.37	2.84
70	1.46	1.59	1.77	2.02	2.46
100	1.23	1.35	1.50	1.75	2.22
200	0.91	1.03	1.21	1.51	2.08
500	0.80	0.94	1.15	1.47	2.06

Table 5-8. Fuel Transportation Costs

Mode of Travel	Cost; ¢/TON-MILE
Rail	7
Rail-Barge Combined	6
Barge	5
Truck	15

The values in Table 5-8 should be multiplied by the appropriate conversion factors to convert to the $/MM Btu basis used for all cost components in the LP model. A factor of 1.4 can be used to adjust costs to a 1980 basis. In lieu of actual cost data, the resulting estimates should adequately account for shipping costs.

5.2.2 Boiler Operation and Maintenance Costs

Highly simplified procedures have been applied to account for the operation and maintenance costs for the boiler, turbine, and associated equipment. Obviously the change in fuel quality resulting from ash and pyrite reduction can affect pulverizer wear, conveyor requirements, and burner maintenance. To account for this cost, a variable B has been calculated according to the equation below:

$$B = 0.5 + M(0.2), \$/MM \text{ Btu}.$$

The variable M is allowed to vary from 0 to 2 depending on the ash content of the feed coal. Values greater than 1.0 represent increases in ash content above the design level, whereas reductions in ash content are accounted for with M values less than 1. The 0.5 $/MM Btu constant represents amortization cost and a general operating cost not affected by changes in fuel properties.

5.2.3 Fuel Costs

Typical fuel costs on a $/MM Btu basis have been presented in Table 3-1. These are based on internal PEDCo data

and are not intended to represent cost for any one coal source.

Fuel costs were one of the most powerful variables affecting the LP solution. The user is strongly encouraged to use actual costs based on coal contracts or other reliable bases.

5.2.4 Purchased Power Costs

The load demand on a typical utility boiler network varies seasonally and diurnally. Total system load can vary from as low as 35 to 40 percent at night to 100 percent at peak periods during the day. Linear programming must derive the optimum solution while allowing for SO_2 emission compliance at all individual boilers during peak periods. This generally requires somewhat greater reliance on low sulfur fuel and on desulfurization systems than in the solution at the average load level. During "average" conditions it is sometimes possible to minimize the power generation at plants subject to stringent SO_2 regulations.

Peaking requirements also affect the amount of purchased power that may be necessary. The FGD system demands between 2 to 6 percent of station power.[4] When the load factor on a network exceeds 94 to 98 percent it is necessary to obtain supplemental power in order to satisfy the needs of the FGD system. This can be obtained from peaking units within the network or from external sources within the same energy pool. In either case, a cost of 30 mills/kWh has been assumed. With an actual network it would be possible to refine these estimates by taking into account capital costs for peaking boilers (e.g., gas turbines) and for transmission equipment.

5.3 COMPILATION OF INPUT DATA FOR THREE PLANT SCENARIO

Regardless of the specific LP program selected (IBM-MPS, UNIVAC-FMPS, etc.), the user is encouraged to compile data described in Sections 5.1 and 5.2 into a set of matrices. Experience indicates that the matrices facilitate input of all data into the LP program. This network consists of three power plants (a fourth power plant variable was added to represent purchased power) and four mines (a fifth mine was added to represent a source of purchasable power). The following notation is used:

DCC1 = coal from mine D that is cleaned, placed in the clean stream (C) and sent to Plant 1.

DCM1 = coal from mine D that is cleaned, placed in the middling stream (M) and sent to Plant 1.

The other symbols used are consistent with this notation. One matrix for the cost coefficients for the small network scenario (see Section 4) is provided in Table 5-9. Table 5-10 illustrates the calculations necessary to compute the coefficients in the SO_2 regulation constraints. The constraints for the three plant scenario are very similar to those for the one plant (see Section 3.1).

In addition, a constraint was necessary to tie the three plants together. The network constraint assures that at least a minimum amount of power is supplied by the three plant system.

5.4 COMPILATION OF INPUT DATA FOR SEVEN PLANT SCENARIO

This scenario consists of seven power plants (plus one to represent purchased power) and nine coal sources (plus a tenth to represent purchasable power). Although the input procedure is similar to that shown previously for the one and three plant cases, there are a few differences due to the increased complexity of the system.

Table 5.9. INPUT COST DATA MATRIX FOR 3-PLANT SCENARIO[a]

Variable	Coal	Clean	Transp	FGD	ESP	Boiler Operation and Maintenance[c]	Total
A1	1.60	0	0.28	0	0.13	0.70	2.71
A1F	1.60	0	0.28	0.60	0.13	0.70	3.31
A2	1.60	0	0.28	0	0.13	0.70	2.71
A2F	1.60	0	0.28	0.82	0.13	0.70	3.53
A3	1.60	0	0.28	0	0.13	0.70	2.71
A3F	1.60	0	0.28	0.53	0.13	0.70	3.24
B1	0.42	0	0.92	0	0.13	0.90	2.37
B1F	0.42	0	0.92	0.60	0.13	0.90	2.97
B2	0.42	0	0.92	0	0.13	0.90	2.37
B2F	0.42	0	0.92	0.82	0.13	0.90	3.19
B3	0.42	0	0.92	0	0.13	0.90	2.37
B3F	0.42	0	0.92	0.53	0.13	0.90	2.90
C1	0.97	0	0.41	0	0.065	0.80	2.245
C1F	0.97	0	0.41	0.60	0.065	0.80	2.845
C2	0.97	0	0.41	0	0.065	0.80	2.245
C2F	0.97	0	0.41	0.82	0.065	0.80	3.065
C3	0.97	0	0.41	0	0.065	0.80	2.245
C3F	0.97	0	0.41	0.53	0.065	0.80	2.775
D1	0.70	0	0.09	0	0	0.70	1.49
D1F	0.70	0	0.09	0.60	0	0.70	2.09
D2	0.70	0	0.09	0	0	0.70	1.49
D2F	0.70	0	0.09	0.82	0	0.70	2.31
D3	0.70	0	0.09	0	0	0.70	1.49
D3F	0.70	0	0.09	0.53	0	0.70	2.02
E4	3.00	0	0	0	0	0	3.00
DCC1	0	0	0.08[b]	0	0	0.50	0.58
DCC1F	0	0	0.08	0.60	0	0.50	1.18
DCC2	0	0	0.08	0	0	0.50	0.58
DCC2F	0	0	0.08	0.82	0	0.50	1.40
DCC3	0	0	0.08	0	0	0.50	0.58
DCC3F	0	0	0.08	0.53	0	0.50	1.11
DCM1	0	0	0.09	0	0	0.70	0.79
DCM1F	0	0	0.09	0.60	0	0.70	1.39
DCM2	0	0	0.09	0	0	0.70	0.79
DCM2F	0	0	0.09	0.82	0	0.70	1.61
DCM3	0	0	0.09	0	0	0.70	0.79
DCM3F	0	0	0.09	0.53	0	0.70	1.32
DCR1	0	0	0.43	0	0	1.00	1.43
DCR1F	0	0	0.43	0.60	0	1.00	2.03
DCR2	0	0	0.43	0	0	1.00	1.43
DCR2F	0	0	0.43	0.82	0	1.00	2.25

Table 5.9 (continued)

Variable	Coal	Clean	Transp	FGD	ESP	Boiler Operation and Maintenance[c]	Total
DCR3	0	0	0.43	0	0	1.00	1.43
DCR3F	0	0	0.43	0.53	0	1.00	1.96
DC	0.70	0	0	0	0	0	0.70
DCC	0	0.197	0	0	0	0	0.197
DCM	0	0.193	0	0	0	0	0.193
DCR	0	0	0	0	0	0	0

[a]See Table 4-3.

[b]See Table 4-2, OPTION C for the transportation costs of the cleaned coal streams.

[c]Boiler costs vary with the type of coal being used; thus, the cost differs depending on the source of the coal. The cost also changes if the coal is first cleaned; cost clean stream (C), being a higher grade coal, burns cleaner, and thus less boiler maintenance is required than would be necessary if stream (M) were used.

Table 5-10. COMPUTATION OF COEFFICIENTS IN SO_2 REGULATION CONSTRAINTS FOR 3-PLANT SCENARIO

Variable	Actual Lb SO_2/MM Btu[a]	Lb SO_2/MM Btu Emission Regulations	Difference
Regulation 1:			
A1	1.28	1.2	0.08
A1F	0.192	1.2	-1.008
B1	1.23	1.2	0.03
B1F	0.1845	1.2	-1.0155
C1	1.30	1.2	0.1
C1F	0.195	1.2	-1.005
D1	6.96	1.2	5.76
D1F	1.044	1.2	-0.156
DCC1	5.47[b]	1.2	4.27
DCC1F	0.8205	1.2	-0.2795
DCM1	7.99	1.2	6.79
DCM1F	1.1985	1.2	0.0015
DCR1	121.0	1.2	119.8
DCR1F	18.15	1.2	16.95
Regulation 2:			
A2	1.28	1.8	-0.52
A2F	0.192	1.8	-1.608
B2	1.23	1.8	-0.57
B2F	0.1845	1.8	-1.6155
C2	1.30	1.8	-0.5
C2F	0.195	1.8	-1.605
D2	6.96	1.8	5.16
D2F	1.044	1.8	-0.756
DCC2	5.47	1.8	3.67
DCC2F	0.8205	1.8	-0.9795
DCM2	7.99	1.8	6.19
DCM2F	1.1985	1.8	-0.6015
DCR2	121.0	1.8	119.2
DCR2F	18.15	1.8	16.35

Table 5-10 (continued)

Variable	Actual Lb SO_2/MM Btu[a]	Lb SO_2/MM Btu Emission Regulations	Difference
Regulation 3:			
A3	1.28	1.8	-0.52
A3F	0.192	1.8	-1.608
B3	1.23	1.8	-0.57
B3F	0.1845	1.8	-1.6155
C3	1.30	1.8	-0.5
C3F	0.195	1.8	-1.605
D3	6.96	1.8	5.16
D3F	1.044	1.8	-0.756
DCC3	5.47	1.8	3.67
DCC3F	0.8205	1.8	-0.9795
DCM3	7.99	1.8	6.19
DCM3F	1.1985	1.8	-0.6015
DCR3	121.0	1.8	119.2
DCR3F	18.15	1.8	16.35

[a]Multiplied by 0.15 when the variable corresponds to a boiler utilizing an FGD system to reflect an 85 percent removal efficiency.

[b]See Table 4-2, OPTION C for the sulfur content of the cleaned coal streams.

The major difference involves the computation of the coefficients in the objective function. Because of the large size of this network it was necessary to consider transportation costs more carefully. Thus, a matrix was developed showing travel distances and associated transportation costs between the various mines and plants. This information is given in Table 5-11. Table 5-12 shows the previous table in the units compatible with the other variables for input into the program, $/MM Btu, and also includes the transportation costs for the cleaned coal streams. Table 5-13 gives the costs at the boiler as they depend on the type of coal used. Tables 5-12 and 5-13 can then be used to compute the coefficients for each of the variables in the objective function. The costs, depending on the source of the coal and its destination (boiler with or without an FGD system), are added together to become the cost coefficients for the variable representing that particular path of flow in the objective function.

Similarly to that done previously, the coefficients in the SO_2 regulation constraint are computed in the following manner:

sulfur content of coal[a] - emission regulation of boiler (lb SO_2/MM Btu)

The output from one run of this scenario is displayed in Appendix A.

5.4.1 Component Process Scale

The size (capacity) of physical coal cleaning plants and flue gas desulfurization systems has a major influence on the capital costs as indicated in equation 2-3. Depending particularly on boiler age, boiler load factors, and various economic factors, these capital costs increase annualized costs of power plant network. The nonlinearities

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[a] See Table 5-14 and 5-15.
Multiply by 0.15 if boiler utilizes an FGD system to reflect an 85 percent SO_2 removal efficiency.

Table 5-11. TRANSPORTATION COSTS AND DISTANCES

FOR 7-PLANT SCENARIO

Source	Plant							
	1	2	3	4	5	6	7	8[c]
A	8.3[a] 750[b]	8.5 650	8.3 700	8.2 900	10 600	9.0 700	9.5 600	- -
B	10 1000	10 1150	10 1100	9.5 1000	9.5 1300	9.5 1200	9.5 1300	- -
C	10 1500	10 1650	10 1600	10 1350	9.5 1800	9.7 1600	9.7 1700	- -
D	8.0 100	8.0 100	8.0 150	9.0 350	10 400	8.5 400	10 400	- -
E	8.5 150	9.5 300	9.0 300	9.0 400	9.0 500	8.5 500	9.0 500	- -
F	8.0 100	8.0 50	8.0 100	9.0 300	10 300	8.5 300	10 300	- -
G	8.0 100	8.0 150	8.0 200	9.0 350	10 400	8.5 350	10 400	- -
H	8.0 100	8.0 150	8.0 200	9.0 350	10 400	8.5 350	10 400	- -
I	8.0 300	9.0 300	8.5 200	9.0 350	8.0 150	8.0 50	10 10	- -
J	- -	- -	- -	- -	- -	- -	- -	- -

[a]Cost coefficient in mills/ton-mile. This is computed by taking the average of the costs of the modes of transport used weighted by the portion of the total distance that mode was used. The costs are as follows: barge - $0.008/ton-mile, rail - $0.010/ton-mile, truck $0.015/ton-mile.

[b]Distance in miles.

[c]Purchased power.

Table 5-12. TRANSPORTATION COSTS, $/MM Btu

FOR 7-PLANT SCENARIO

Mine	Coal stream	Plant							
		1	2	3	4	5	6	7	8[a]
A	-	0.249	0.221	0.232	0.295	0.240	0.280	0.240	-
B	-	0.410	0.472	0.451	0.390	0.988	0.912	0.988	-
C	-	0.920	1.012	0.982	0.828	0.960	0.853	0.906	-
D	-	0.033	0.033	0.050	0.130	0.166	0.141	0.166	-
D	C	0.030	0.030	0.045	0.119	0.151	0.128	0.128	-
D	M	0.047	0.047	0.071	0.186	0.236	0.200	0.200	-
D	R	0.325	0.325	0.488	1.282	1.627	1.383	1.383	-
E	-	0.057	0.127	0.120	0.160	0.200	0.189	0.200	-
E	C	0.048	0.108	0.102	0.136	0.171	0.162	0.171	-
E	M	0.062	0.139	0.132	0.176	0.219	0.207	0.219	-
E	R	0.779	1.742	1.650	2.200	2.750	2.597	2.750	-
F	-	0.035	0.019	0.035	0.127	0.141	0.120	0.141	-
F	C	0.031	0.016	0.031	0.105	0.116	0.099	0.116	-
F	M	0.049	0.024	0.049	0.164	0.183	0.156	0.183	-
F	R	0.469	0.234	0.469	1.585	0.761	1.497	.1761	-
G	-	0.035	0.053	0.070	0.148	0.170	0.126	0.170	-
G	C	0.031	0.047	0.062	0.122	0.154	0.115	0.154	-
G	M	0.049	0.074	0.098	0.192	0.201	0.149	0.201	-
G	R	0.469	0.704	0.938	1.849	1.938	1.441	1.938	-
H	-	0.034	0.051	0.068	0.134	0.178	0.132	0.178	-
H	C	0.031	0.046	0.062	0.121	0.152	0.113	0.152	-
H	M	0.040	0.060	0.080	0.158	0.202	0.150	0.202	-
H	R	0.388	0.582	0.776	1.526	2.215	1.647	2.215	-
I	-	0.107	0.121	0.076	0.141	0.054	0.121	0.004	-
H	-	-	-	-	-	-	-	-	-

[a]Purchased power.

Table 5-13. COST DATA FOR 7-PLANT SCENARIO

Mine	Coal cost	Coal stream	Coal cleaning	Boiler Operation and Maintenance S/MM Btu	Flue gas* cleaning	ESP Modification $/MM Btu
A	1.60	-	0	0.2	0.40	0.065
B	0.97	-	0	0.3	0.40	0.065
C	0.42	-	0	0.4	0.40	0.130
D	0.70	-	0	0.2	0.40	0
D	-	C	0.10	0	0.40	0
D	-	M	0.10	0.2	0.40	0
D	-	R	0	0.5	0.40	0
E	0.70	-	0	0.2	0.40	0
E	-	C	0.10	0	0.40	0
E	-	M	0.10	0.2	0.40	0
E	-	R	0	0.5	0.40	0
F	0.70	-	0	0.2	0.40	0
F	-	C	0.10	0	0.40	0
F	-	M	0.10	0.2	0.40	0
F	-	R	0	0.5	0.40	0
G	0.70	-	0	0.2	0.40	0
G	-	C	0.10	0	0.40	0
G	-	M	0.10	0.2	0.40	0
G	-	R	0	0.5	0.40	0
H	1.30	-	0	0.2	0.40	0
H	-	C	0.10	0	0.40	0
H	-	M	0.10	0.2	0.40	0
H	-	R	0	0.5	0.40	0
I	3.00	-	0	0.2	0.40	0.065
J	3.00	-	0	0	0	0

*Included in cost coefficient only if associated with a variable that represents a boiler utilizing an FGD system.

Table 5-14. COAL CHARACTERISTICS - 7-PLANT SCENARIO

Mine	Coal stream	Sulfur content lb SO_2/MM Btu	Heating value Btu/lb	% weight	% Btu
A	-	1.28	12,500	100.0	100.0
B	-	1.30	12,150	100.0	100.0
C	-	1.23	8,160	100.0	100.0
D	-	6.76	12,074	100.0	100.0
D	C	5.47	12,924	76.1	85.9
D	M	7.99	10,229	14.6	13.1
D	R	223.40	1,229	9.3	1.0
E	-	5.64	10,985	100.0	100.0
E	C	3.49	12,780	68.8	82.5
E	M	5.24	10,261	17.0	16.4
E	R	152.60	818	14.2	1.1
F	-	8.34	10,502	100.0	100.0
F	C	5.32	12,406	75.2	91.3
F	M	11.56	6,918	11.2	7.6
F	R	219.70	857	13.6	1.1
G	-	6.21	11,502	100.0	100.0
G	C	4.49	12,729	73.5	84.7
G	M	7.62	9,577	16.6	14.4
G	R	178.90	1,032	9.9	0.9
H	-	7.72	10,971	100.0	100.0
H	C	4.77	12,719	25.7	31.7
H	M	7.47	9,825	64.4	67.4
H	R	239.00	903	9.9	0.9
I	-	1.71	11,169	100.0	100.0
J	-	0	0	100.0	100.0

Table 5-15. SO_2 EMISSION CONSTRAINTS, LB SO_2/MM BTU

Plant	1	2	3	4	5	6	7	8
Emission Regulation	1.2	5.2	5.0	4.0	1.2	4.0	1.2	None

are particularly important for FGD systems with less than 150 MW throughput capacity[b] and for coal cleaning plants with less than 300 tons/hour throughput. To avoid unrealistic cost estimates, lower limits of 50 MW capacity for an FGD system and 200 tons per hour for coal cleaning plants have been assumed. The computer model used for FGD incorporates an upper limit for scrubbers by providing sets of equal size scrubber trains in a module for facilities requiring large flue gas desulfurization systems. An upper limit of 3000 tons per hour has been assumed for coal cleaning plants.

The use of flue gas scrubber modules on a boiler is represented more accurately by a step function than the linear function which must be used in a linear programming model. During the iterative procedure, capacity constraints have been modified as necessary to approximate a step function. If the optimal solution involved flue gas scrubbing of less than 25 percent of the boiler effluent gas, the use of FGD was prohibited entirely at that boiler.

Raw coal sources providing less than 2 percent of network demand or less than 10^5 MM Btu/ year were dropped during subsequent analyses. Transport of small quantities of coal may cost well in excess of the estimates used.

5.4.2 Derating

The derating of a boiler or set of boilers within a power plant network results from the energy demand of flue gas desulfurization systems and/or from the marginal suitability of some low sulfur coal supplies.[5] The coal compatibility problems are particularly difficult to incorporate into the calculation models since the extent of derating is a nonlinear function of the characteristics of the coal feed to a particular boiler. Conversely, the

---

[b] The size of an FGD system is most accurately characterized by the gas throughput at design gas velocity; however, specifications of size according to the equivalent size boiler is a more convenient basis for the purposes of this report.

energy demand can be handled easily as a simple factor in the overall fuel cost. Both general types of boiler derating must be considered in order to refine the boiler generation constraints and the boiler energy production costs.

The combustion of low Btu, high moisture content, western coals in existing boilers designed for higher quality coals can result in both materials handling and boiler operation problems. More material per unit of output power must be handled when the low Btu coals are burned. Capacity limitations for crushers, pulverizers, or conveyors may preclude achievement of design load. Generally these limitations can be overcome by modifying operating practices (speeding up conveyors) or adding additional equipment. Boiler operational problems are more difficult to circumvent.

The following general operational problems can complicate conversion of existing boilers to low sulfur western coals.[5]

1. The low Btu, high moisture content, western coals produce greater quantities of effluent gas, thereby increasing furnace gas velocity and pressure losses.

2. Increases in furnace slagging affect the heat absorption patterns in the lower and upper furnace areas and result in steam temperature control problems.

3. The low Btu, high moisture coals reduce furnace/boiler efficiency.

These boiler operational problems and material handling limitations can result in a derating from zero to 20 percent.[5] In most cases, derating can be minimized by selection of coal supplies moderately compatible with the exist-

ing power plant design. It is conceivable that the optimal solution derived from the linear programming models will involve less desirable coals at several of the boilers in a network. Therefore, it will be necessary to approximate the nonlinear derating requirements. For simplicity, a function can be assumed which is based on heating value. As shown in Figure 5-3, the extent of derating is maintained near zero in a region around the design point of the original boiler fuel. As the coal heating value decreases below 10,000 Btu/lb (dry), the extent of derating increases exponentially up to a maximum of 20 percent. Slight increases in production capacity are assumed if the coal quality increases substantially.

The energy requirements of SO_2 control systems could conceivably necessitate an increase in the generating capacity of the network. These capital costs have not been included in the present calculations, but could be approximated as $400/kW installed.[6]

5.4.3 Particulate Control

As discussed earlier, electrostatic precipitator costs are dependent on the average sulfur content of the feed coal. In turn, the feed coal characteristics are a function of this solution. Therefore, it is necessary to adjust ESP after each run.

5.4.4 Iterative Procedure

Due to the nonlinearities in some of the cost relationships used in this study, an iterative procedure is used to converge to an acceptable solution. Fortunately, the iterative approach converges quickly with proper selection of initial conditions. This involves optimizing the scale of desulfurization facilities and physical coal cleaning plants.

For the initial computer run the cost coefficients for FGDs and CCPs are purposely underestimated to maximize the use of these processes. During each successive run the coefficients are adjusted upward to match the computer derived equipment scale of FGDs and CCPs for each power plant or boiler. This process converges on a solution which generally consists of the minimum necessary level of flue gas desulfurization and coal cleaning for each boiler. The electrostatic precipitator costs are a function of the average sulfur content into the boiler and must be recalculated for each computer iteration in which a change in average sulfur content is implied. The ESP costs do not necessarily follow the consistent patterns forced on FGD and CCP costs. After each run the boilers are derated as necessary to account for the average heating value of the feed coal to the boiler. Also, any FGD or CCP units which do not satisfy minimum size requirements are deleted.

The adjustments listed above result in convergence to an acceptable solution in several iterations. Once the technical constraints are satisfied and the cost coefficients are accurate, the base case can be calculated. This is the minimum total annualized cost under present system conditions as obtained through the use of LP. Potential cost savings can be computed by comparison with base costs. These savings must be weighed against possible capital costs for desulfurization systems, coal cleaning plants, and ESP/boiler modifications. Capital costs are calculated from the results of the separate estimation models.

The IBM-MPS (Mathematical Programming System) used in this project provides the capability for sensitivity analyses useful in identifying the most important variables with respect to total annualized cost. Generally these con-

straints include the SO_2 emission limitations, network load factor, and fuel costs. The parameter adjustment procedures of the MPS will automatically vary the selected cost coefficient in one set of runs. The results are useful in determining if the optimum strategy predicted from the base case run is economical over a wide range of conditions. The parameter adjustment option is a major advantage of the linear programming technique since the cost per run and/or the number of runs are substantially reduced.

6.0 CONCLUSIONS AND RECOMMENDATIONS

The following conclusions are derived on the basis of several scenarios utilized for demonstrating the application of linear programming techniques to the determination of a least cost combined strategy for SO_2 control.

1. The linear programming techniques can be used to determine least cost solutions for reasonably general scenarios in terms of numbers of coal sources/mines, coal cleaning plant design and resulting coal characteristics, and the presence or absence of an FGD system.

2. The cost coefficients, particularly the fuel costs, are very critical as they determine the structure of the solution, e.g., which coal sources are used.

3. The emission regulations also play a critical role in the determination of the optimal solution.

4. Optimal solutions can be obtained as a function of specific parameters such as FGD or coal cleaning plant costs, i.e., a sensitivity analysis of the impact of the parameters on the overall annualized cost.

5. The fact that certain costs are non-linear functions of the amount of coal, the decision variable, does not deter the usage of a linear programming technique. An iterative solution converges on the best solution by using the cost estimate for the nth iteration based on the plant size implied by the n-1 th iteration, i.e., for the amount of coal determined by the previous iteration. An alternative approach uses the concept of separable programming as described in the manual.[3]

6. The uncertainty in certain cost estimates may be treated by methods described in reference 8 provided some prior information can be used to infer the probability or likelihood of certain cost values or a continuous frequency distribution of these costs.

The following recommendations are made for the purpose of defining areas for follow on studies.

1. A computer program should be written to solicit and accept data for flexible configurations of power plants, mines, coal cleaning plants, FGD systems, etc. and to perform calculations and properly format data for input to the Mathematical Programming System (MPS). This program would reduce the likelihood for error inherent in the manual calculation and input procedure and would permit the data to be expressed in the most commonly used units.

2. The features of MPS should be more fully exploited in performing sensitivity analyses and iterative solutions where costs are nonlinear functions of the amount of coal.

3. The separable programming features of MPS should also be investigated as this will permit the use of linear approximations to nonlinear functions.

4. The optimization approach can be applied to both the capital costs and the annual operating and maintenance cost. A solution could be obtained by minimizing the total annualized cost, subject to a limitation on the total capital cost, or using a multiple objective optimization approach.

5. More refined cost estimates should be made subsequent to the least cost solution. These costs would be determined in the same manner as a utility company would determine their daily coal requirements, boiler loading, etc.

6. The linear programming technique, including the interactive data input routine, should be converted to run on EPA's UNIVAC 1110 using the Functional Mathematical Programming System (FMPS) already installed on the 1110.

7.0 REFERENCES

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3. Mathematical Programming System/360, Version 3, Linear and Separable Programming - User's Manual (360A-CO-14x). IBM Corporation, Technical Publications Department, October 15, 1971.

4. Flue Gas Desulfurization Process Cost Assessment. PEDCo Environmental, Inc. Contract No. 68-01-3150, Task 2, U.S. Environmental Protection Agency, May 1975.

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8.0 GLOSSARY

The following terms used in this report or its appendices are defined in order to aid the reader who may not be familiar with the technologies discussed.

Combined strategy - The use of multi-stream coal cleaning in conjunction with flue gas desulfurization and fuel supply redistribution to achieve compliance with emission regulations at all plants of a network at a minimum cost.

Flue gas desulfurization - One or more trains each of which contains ducting, absorber, holding tank, agitators, recirculation pump(s), demistor, reheater, soot blowers, ducting shut-off valves, piping, and controls.

Heat rate - A measure of generator thermal efficiency expressed in Btu/net kWh.

Heavy medium vessel - A device employing a liquid having a specific gravity higher than water to effect a gravimetric (float-sink) separation of coal particles from impurities.

Linear Programming - A mathematical technique designed to analyze the costs of alternate decisions and to choose those that permit the best use of resources in the pursuit of a desireable objective.

Low sulfur coal - Coal having a sufficiently low total sulfur content so that it can be burned without fuel treatment for pyritic reduction or without flue gas desulfurization for SO_2 removal. The term generally applies to coal supplies of less than an equivalent sulfur content of 1.5 lb

SO_2/MM Btu.

Multi-stream coal cleaning - A physical coal cleaning process in which two or more usable coal streams of different qualities and at least one reject coal stream are generated.

APPENDIX A SELECTED COMPUTER RESULTS
ONE PLANT SCENARIO

```
ROWS
 N  COST
 L  MINE1
 L  MINE2
 L  MINE3
 L  MINE4
 L  BOILER1
 L  BOILER2
 G  PLANT
 L  SO2A1
 L  SO2A2
 E  AW
 E  MW
 E  RW
 L  S4AC
 L  S4MC
 L  S4RC
COLUMNS
    S1B1      COST          2.01500   BOILER1       1.00000
    S1B1      SO2A1     -   2.72000   MINE1         1.00000
    S1B1      PLANT         1.00000
    S1B2      COST          2.01500   BOILER2       1.00000
    S1B2      SO2A2     -    .52000   MINE1         1.00000
    S1B2      PLANT         1.00000
    S1B2F     COST          2.61500   BOILER2       1.00000
    S1B2F     SO2A2     -   1.60800   MINE1         1.00000
    S1B2F     PLANT         1.00000
    S2B1      COST          1.63000   BOILER1       1.00000
    S2B1      SO2A1     -   2.77000   MINE2         1.00000
    S2B1      PLANT         1.00000
    S2B2      COST          1.63000   BOILER2       1.00000
    S2B2      SO2A2     -    .57000   MINE2         1.00000
    S2B2      PLANT         1.00000
    S2B2F     COST          2.23000   BOILER2       1.00000
    S2B2F     SO2A2     -   1.61500   MINE2         1.00000
    S2B2F     PLANT         1.00000
    S3B1      COST          1.75500   BOILER1       1.00000
    S3B1      SO2A1     -   2.70000   MINE3         1.00000
    S3B1      PLANT         1.00000
    S3B2      COST          1.75500   BOILER2       1.00000
    S3B2      SO2A2     -    .50000   MINE3         1.00000
    S3B2      PLANT         1.00000
    S3B2F     COST          2.35500   BOILER2       1.00000
    S3B2F     SO2A2     -   1.60500   MINE3         1.00000
    S3B2F     PLANT         1.00000
    S4C       MW        -    .28000   RW        -    .01200
    S4C       COST          1.01000   AW        -    .70800
    S4C       MINE4         1.00000
    S4CA      AW            1.00000   S4AC      -   1.00000
    S4CM      MW            1.00000   S4MC      -   1.00000
    S4CR      RW            1.00000   S4RC      -   1.00000
    S4B1      COST          1.05000   BOILER1       1.00000
    S4B1      SO2A1         2.50000   MINE4         1.00000
```

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```
    S4B1      PLANT          1.00000
    S4AB1     COST            .14000   BOILER1        1.00000
    S4AB1     SO2A1    -      .20000   PLANT          1.00000
    S4AB1     S4AC           1.00000
    S4MB1     COST            .16000   BOILER1        1.00000
    S4MB1     SO2A1          4.54000   PLANT          1.00000
    S4MB1     S4MC           1.00000
    S4RB1     COST            .59000   BOILER1        1.00000
    S4RB1     SO2A1        105.00000   PLANT          1.00000
    S4RB1     S4RC           1.00000
    S4B2      COST           1.05000   BOILER2        1.00000
    S4B2      SO2A2          4.70000   MINE4          1.00000
    S4B2      PLANT          1.00000
    S4AB2     COST            .14000   BOILER2        1.00000
    S4AB2     SO2A2          2.00000   PLANT          1.00000
    S4AB2     S4AC           1.00000
    S4MB2     COST            .16000   BOILER2        1.00000
    S4MB2     SO2A2          6.74000   PLANT          1.00000
    S4MB2     S4MC           1.00000
    S4RB2     COST            .59000   BOILER2        1.00000
    S4RB2     SO2A2        107.20000   PLANT          1.00000
    S4RB2     S4RC           1.00000
    S4B2F     COST           1.65000   BOILER2        1.00000
    S4B2F     SO2A2    -      .82500   MINE4          1.00000
    S4B2F     PLANT          1.00000
    S4AB2F    COST            .74000   BOILER2        1.00000
    S4AB2F    SO2A2    -     1.23000   PLANT          1.00000
    S4AB2F    S4AC           1.00000
    S4MB2F    COST            .76000   BOILER2        1.00000
    S4MB2F    SO2A2    -      .51900   PLANT          1.00000
    S4MB2F    S4MC           1.00000
    S4RB2F    COST           1.19000   BOILER2        1.00000
    S4RB2F    SO2A2         14.55000   PLANT          1.00000
    S4RB2F    S4RC           1.00000
RHS
    RHS       BOILER1    34690.00000   BOILER2    86724.00000
    RHS       MINE1      70000.00000   MINE2      70000.00000
    RHS       MINE3      70000.00000   MINE4      70000.00000
    RHS       PLANT      69206.00000
ENDATA
```

SECTION 1 - ROWS

NUMBER	...ROW...	AT	...ACTIVITY...	..SLACK ACTIVITY	..LOWER LIMIT.	..UPPER LIMIT.	.DUAL ACTIVITY
1	COST	BS	95027.93684	95027.93684-	NONE	NONE	1.00000
2	MINE1	BS	.	70000.00000	NONE	70000.00000	.
3	MINE2	BS	.	70000.00000	NONE	70000.00000	.
4	MINE3	BS	.	70000.00000	NONE	70000.00000	.
5	MINE4	BS	69891.87720	108.12280	NONE	70000.00000	.
6	BOILER1	UL	34690.00000	.	NONE	34690.00000	.30912
7	BOILER2	BS	34516.00000	52208.00000	NONE	86724.00000	.
8	PLANT	LL	69206.00000	.	69206.00000	NONE	1.52806-
9	SO2A1	UL	.	.	NONE	.	.06758
10	SO2A2	UL	.	.	NONE	.	.14780
11	AM	EQ	.	.	.	.	1.09246
12	MM	EQ	.	.	.	.	.84477
13	AM	EQ	.	.	.	.	.
14	S4AC	UL	.	.	NONE	.	1.09246
15	S4MC	UL	.	.	NONE	.	.84477
16	S4MC	BS	885.87720-	885.87720	NONE	.	.

SECTION 2 - COLUMNS

NUMBER	.COLUMN.	AT	...ACTIVITY...	..INPUT COST..	..LOWER LIMIT.	..UPPER LIMIT.	.REDUCED COST.
17	S1B1	LL	.	2.01500	.	NONE	.61224
18	S1B2	LL	.	2.01500	.	NONE	.41008
19	S1B2F	LL	.	2.01500	.	NONE	.84927
20	S2B1	LL	.	1.63000	.	NONE	.22386
21	S2B2	LL	.	1.63000	.	NONE	.01769
22	S2B2F	LL	.	2.23000	.	NONE	.46324
23	S3B1	LL	.	1.75500	.	NONE	.35359
24	S3B2	LL	.	1.75500	.	NONE	.15304
25	S3B2F	LL	.	2.35500	.	NONE	.58972
26	S4C	BS	57156.43371	1.01000	.	NONE	.
27	S4CA	BS	40406.75506	.	.	NONE	.
28	S4CB	BS	16003.80144	.	.	NONE	.
29	S4CF	BS	885.87720	.	.	NONE	.
30	S4B1	BS	2569.62963	1.05000	.	NONE	.
31	S4AB1	BS	32120.37037	.14000	.	NONE	.
32	S4MB1	LL	.	.16000	.	NONE	.09263
33	S4BB1	LL	.	.59000	.	NONE	6.46682
34	S4B2	LL	.	1.05000	.	NONE	.21660
35	S4AB2	BS	8346.38469	.14000	.	NONE	.
36	S4MB2	LL	.	.16000	.	NONE	.47289
37	S4BB2	LL	.	.59000	.	NONE	14.90618
38	S4B2F	BS	10165.81387	1.65000	.	NONE	.
39	S4AB2F	LL	.	.74000	.	NONE	.12260
40	S4MB2F	BS	16003.80144	.76300	.	NONE	.
41	S4BB2F	LL	.	1.19000	.	NONE	1.81244

3 PLANT SCENARIO

```
NAME          STRATA
ROWS
 N  COST
 G  NETWORK
 L  FGD1
 L  FGD2
 L  FGD3
 L  PLANT1
 L  PLANT2
 L  PLANT3
 L  PLANT4
 L  MINEA
 L  MINEB
 L  MINEC
 L  MINED
 L  MINEE
 L  REG1
 L  REG2
 L  REG3
 L  CLEAN
 L  MIDDLING
 L  REJECT
 E  DCC
 E  DCM
 E  DCR
COLUMNS
    A1        COST              2.64500   MINEA          1.00000
    A1        REG1               .08000   PLANT1         1.00000
    A1        NETWORK           1.00000
    A1F       COST              3.24500
    A1F       REG1       -      1.00800   MINEA          1.00000
    A1F       NETWORK           1.00000   PLANT1         1.00000
    A2        COST              2.64500   FGD1           1.00000
    A2        REG2       -       .52000   MINEA          1.00000
    A2        NETWORK           1.00000   PLANT2         1.00000
    A2F       COST              3.46500
    A2F       REG2       -      1.60800   MINEA          1.00000
    A2F       NETWORK           1.00000   PLANT2         1.00000
    A3        COST              2.64500   FGD2           1.00000
    A3        REG3       -       .52000   MINEA          1.00000
    A3        NETWORK           1.00000   PLANT3         1.00000
    A3F       COST              3.17500
    A3F       REG3       -      1.60800   MINEA          1.00000
    A3F       NETWORK           1.00000   PLANT3         1.00000
    B1        COST              2.37000   FGD3           1.00000
    B1        REG1               .03000   MINEB          1.00000
    B1        NETWORK           1.00000   PLANT1         1.00000
    B1F       COST              2.97000
    B1F       REG1       -      1.01000   MINEB          1.00000
    B1F       NETWORK           1.00000   PLANT1         1.00000
    B2        COST              2.37000   FGD1           1.00000
    B2        REG2       -       .57000   MINEB          1.00000
    B2        NETWORK           1.00000   PLANT2         1.00000
    B2F       COST              3.19000   MINEB          1.00000
```

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3 PLANT SCENARIO

B2F	REG2	-	1.61500	PLANT2	1.00000
B2F	NETWORK		1.00000	FGD2	1.00000
B3	COST		2.37000	MINEB	1.00000
B3	REG3	-	.57000	PLANT3	1.00000
B3	NETWORK		1.00000		
B3F	COST		2.90000	MINEB	1.00000
B3F	REG3	-	1.61500	PLANT3	1.00000
B3F	NETWORK		1.00000	FGD3	1.00000
C1	COST		2.24500	MINEC	1.00000
C1	REG1		.10000	PLANT1	1.00000
C1	NETWORK		1.00000		
C1F	COST		2.84500	MINEC	1.00000
C1F	REG1	-	1.00500	PLANT1	1.00000
C1F	NETWORK		1.00000	FGD1	1.00000
C2	COST		2.24500	MINEC	1.00000
C2	REG2	-	.50000	PLANT2	1.00000
C2	NETWORK		1.00000		
C2F	COST		3.06500	MINEC	1.00000
C2F	REG2	-	1.60500	PLANT2	1.00000
C2F	NETWORK		1.00000	FGD2	1.00000
C3	COST		2.24500	MINEC	1.00000
C3	REG3	-	.50000	PLANT3	1.00000
C3	NETWORK		1.00000		
C3F	COST		2.77500	MINEC	1.00000
C3F	REG3	-	1.60500	PLANT3	1.00000
C3F	NETWORK		1.00000	FGD3	1.00000
D1	COST		1.49000	MINED	1.00000
D1	REG1		5.76000	PLANT1	1.00000
D1	NETWORK		1.00000		
D1F	COST		2.09000	MINED	1.00000
D1F	REG1	-	.15600	PLANT1	1.00000
D1F	NETWORK		1.00000	FGD1	1.00000
D2	COST		1.49000	MINED	1.00000
D2	REG2		5.16000	PLANT2	1.00000
D2	NETWORK		1.00000		
D2F	COST		2.31000	MINED	1.00000
D2F	REG2	-	.75600	PLANT2	1.00000
D2F	NETWORK		1.00000	FGD2	1.00000
D3	COST		1.49000	MINED	1.00000
D3	REG3		5.16000	PLANT3	1.00000
D3	NETWORK		1.00000		
D3F	COST		2.02000	MINED	1.00000
D3F	REG3	-	.75600	PLANT3	1.00000
D3F	NETWORK		1.00000	FGD3	1.00000
E4	COST		3.00000	MINEE	1.00000
E4	NETWORK		1.00000	PLANT4	1.00000
DCC1	COST		.58000	NETWORK	1.00000
DCC1	REG1		4.27000	PLANT1	1.00000
DCC1	CLEAN		1.00000		
DCC1F	COST		1.18000	NETWORK	1.00000
DCC1F	REG1	-	.37900	PLANT1	1.00000
DCC1F	CLEAN		1.00000	FGD1	1.00000
DCC2	COST		.58000	NETWORK	1.00000
DCC2	REG2		3.67000	PLANT2	1.00000

3 PLANT SCENARIO

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DCC2	CLEAN		1.00000
DCC2F	COST		1.40000
DCC2F	REG2	-	.97900
DCC2F	CLEAN		1.00000
DCC3	COST		.58000
DCC3	REG3		3.67000
DCC3	CLEAN		1.00000
DCC3F	COST		1.11000
DCC3F	REG3	-	.97900
DCC3F	CLEAN		1.00000
DCM1	COST		.79000
DCM1	REG1		6.79000
DCM1	MIDDLING		1.00000
DCM1F	COST		1.39000
DCM1F	REG1	-	.00200
DCM1F	MIDDLING		1.00000
DCM2	COST		.79000
DCM2	REG2		6.19000
DCM2	MIDDLING		1.00000
DCM2F	COST		1.61000
DCM2F	REG2	-	.60200
DCM2F	MIDLIING		1.00000
DCM3	COST		.79000
DCM3	REG3		6.19000
DCM3	MIDDLING		1.00000
DCM3F	COST		1.32000
DCM3F	REG3	-	.60200
DCM3F	MIDDLING		1.00000
DCR1	COST		1.43000
DCR1	REG1		119.80000
DCR1	REJECT		1.00000
DCR1F	COST		2.03000
DCR1F	REG1		16.95000
DCR1F	REJECT		1.00000
DCR2	COST		1.43000
DCR2	REG2		119.20000
DCR2	REJECT		1.00000
DCR2F	COST		2.25000
DCR2F	REG2		16.35000
DCR2F	REJECT		1.00000
DCR3	COST		1.43000
DCR3	REG3		119.20000
DCR3	REJECT		1.00000
DCR3F	COST		1.96000
DCR3F	REG3		16.35000
DCR3F	REJECT		1.00000
DC	COST		.70000
DC	DCC	-	.85900
DC	DCR	-	.01000
DCC	DCC		1.00000
DCC	COST		.19700
DCM	DCM		1.00000
DCM	COST		.19300
DCR	DCR		1.00000

NETWORK		1.00000
PLANT2		1.00000
FGD2		1.00000
NETWORK		1.00000
PLANT3		1.00000
NETWORK		1.00000
PLANT3		1.00000
FGD3		1.00000
NETWORK		1.00000
PLANT1		1.00000
NETWORK		1.00000
PLANT1		1.00000
FGD1		1.00000
NETWORK		1.00000
PLANT2		1.00000
NETWORK		1.00000
PLANT2		1.00000
FGD2		1.00000
NETWORK		1.00000
PLANT3		1.00000
NETWORK		1.00000
PLANT3		1.00000
FGD3		1.00000
NETWORK		1.00000
PLANT1		1.00000
NETWORK		1.00000
PLANT1		1.00000
FGD1		1.00000
NETWORK		1.00000
PLANT2		1.00000
NETWORK		1.00000
PLANT2		1.00000
FGD2		1.00000
NETWORK		1.00000
PLANT3		1.00000
NETWORK		1.00000
PLANT3		1.00000
FGD3		1.00000
MINED		1.00000
DCM	-	.13100
CLEAN	-	1.00000
MIDDLING	-	1.00000
REJECT	-	1.00000

3 PLANT SCENARIO

```
RHS
    RHS       NETWORK      7278.00000   FGD1        3530.00000
    RHS       FGD2         1330.00000   FGD3        6540.00000
    RHS       PLANT1       3000.00000   PLANT2      1160.00000
    RHS       PLANT3       5000.00000   PLANT4     12130.00000
    RHS       MINEA       12130.00000   MINEB      12130.00000
    RHS       MINEC       12130.00000   MINED      12130.00000
    RHS       MINEE       12130.00000
RANGES
    RANGE     PLANT1       1500.00000   PLANT2       560.00000
    RANGE     PLANT3       2800.00000
ENDATA
```

3 PLANT SCENARIO

ECTION 1 - ROWS

NUMBER	...ROW...	AT	...ACTIVITY...	SLACK ACTIVITY	..LOWER LIMIT.	..UPPER LIMIT.	.DUAL ACTIVITY
1	COST	BS	14407.57911	14407.57911-	NONE	NONE	1.00000
2	NETWORK	LL	7278.00000	.	7278.00000	NONE	1.93413-
3	FGD1	BS	1377.71564	2132.28436	NONE	3510.00000	.
4	FGD2	BS	.	1330.00000	NONE	1330.00000	.
5	FGD3	BS	4323.10635	2476.89365	NONE	6800.00000	.
6	PLANT1	LL	1500.00000	1500.00000	1500.00000	3000.00000	.13421-
7	PLANT2	LL	580.00000	580.00000	580.00000	1160.00000	.22361-
8	PLANT3	BS	5198.00000	402.00000	2800.00000	5600.00000	.
9	PLANT4	BS	.	12130.00000	NONE	12130.00000	.
10	MINEA	BS	.	12130.00000	NONE	12130.00000	.
11	MINEB	BS	.	12130.00000	NONE	12130.00000	.
12	MINEC	BS	510.45564	11619.54436	NONE	12130.00000	.
13	MINED	BS	6796.30115	5333.99885	NONE	12130.00000	.
14	MINEE	BS	.	12130.00000	NONE	12130.00000	.
15	REG1	UL	.	.	NONE	.	.12906
16	REG2	UL	.	.	NONE	.	.17452
17	REG3	UL	.	.	NONE	.	.11359
18	CLEAN	UL	.	.	NONE	.	.93725
19	MIDDLING	UL	.	.	NONE	.	.68251
20	REJECT	BS	28.45679-	28.45679	NONE	.	.
21	DCC	EQ	.	.	.	.	.74025
22	DCM	EQ	.	.	.	.	.48951
23	DCE	EQ	.	.	.	.	.

3 PLANT SCENARIO

ECTION 2 - COLUMNS

NUMBER	.COLUMN.	AT	...ACTIVITY...	..INPUT COST..	..LOWER LIMIT.	..UPPER LIMIT.	.REDUCED COST.
24	A1	LL	.	2.64500	.	NONE	.58699
25	A1F	LL	.	3.24500	.	NONE	1.04657
26	A2	LL	.	2.64500	.	NONE	.39651
27	A2F	LL	.	3.46500	.	NONE	1.02663
28	A3	LL	.	2.64500	.	NONE	.65181
29	A3F	LL	.	3.17500	.	NONE	1.05822
30	B1	LL	.	2.37000	.	NONE	.30554
31	B1F	LL	.	2.97000	.	NONE	.77131
32	B2	LL	.	2.37000	.	NONE	.11278
33	B2F	LL	.	3.19000	.	NONE	.75041
34	B3	LL	.	2.37000	.	NONE	.37113
35	B3F	LL	.	2.90000	.	NONE	.78243
36	C1	LL	.	2.24500	.	NONE	.18957
37	C1F	LL	.	2.84500	.	NONE	.64696
38	C2	BS	510.45564	2.24500	.	NONE	.
39	C2F	LL	.	3.06500	.	NONE	.62715
40	C3	LL	.	2.24500	.	NONE	.25408
41	C3F	LL	.	2.77500	.	NONE	.65856
42	D1	LL	.	1.49000	.	NONE	.16505
43	D1F	LL	.	2.09000	.	NONE	.00153
44	D2	LL	.	1.49000	.	NONE	.23279
45	D2F	LL	.	2.31000	.	NONE	.02032
46	D3	LL	.	1.49000	.	NONE	.14200
47	D3F	BS	3950.32244	2.02000	.	NONE	.
48	E4	LL	.	3.00000	.	NONE	1.06587
49	DCC1	BS	122.28436	.58000	.	NONE	.
50	DCC1F	BS	1377.71564	1.18000	.	NONE	.
51	DCC2	BS	69.54436	.58000	.	NONE	.
52	DCC2F	LL	.	1.40000	.	NONE	.00865
53	DCC3	BS	874.89365	.58000	.	NONE	.
54	DCC3F	LL	.	1.11000	.	NONE	.00192
55	DCM1	LL	.	.79000	.	NONE	.28049
56	DCM1F	LL	.	1.39000	.	NONE	.00391
57	DCM2	LL	.	.79000	.	NONE	.39505
58	DCM2F	LL	.	1.61000	.	NONE	.02971
59	DCM3	LL	.	.79000	.	NONE	.24150
60	DCM3F	BS	372.78391	1.32000	.	NONE	.
61	DCR1	LL	.	1.43000	.	NONE	14.82305
62	DCR1F	LL	.	2.03000	.	NONE	2.14923
63	DCR2	LL	.	1.43000	.	NONE	20.07510
64	DCR2F	LL	.	2.25000	.	NONE	2.94567
65	DCR3	LL	.	1.43000	.	NONE	13.03583
66	DCR3F	LL	.	1.96000	.	NONE	1.88307
67	DC	BS	2845.67871	.70000	.	NONE	.
68	DCC	BS	2444.43801	.19700	.	NONE	.
69	DCM	BS	372.78391	.19300	.	NONE	.
70	DCR	BS	28.45679	.	.	NONE	.

APPENDIX B
STATEMENT OF THE PROBLEM IN MATHEMATICAL TERMS

The subject of this study has been coal burning power plants of one or more electric utilities. In particular, the study has considered alternative control methods for compliance with SO_2 emission limitations affecting coal burning activities. The control methods considered included flue gas desulfurization, physical coal cleaning, low sulfur coal, and blending of coals. These methods have been discussed earlier.

From the broadest point of view, the objective of the study was to identify a methodology to aid in selection of the method or combination of methods which would meet the SO_2 emission limitations and satisfy other constraints with the least possible total cost. Thus the problem is one of constrained optimization.

The number of location of coal mines and power plants were taken to be given.

The initial effort attempted to address selection of locations for physical coal cleaning plants (CCP) and flue gas desulfurization (FGD) systems. The FGD systems must be located at the power plants they are to serve. However, CCP's could be located anywhere, at least theoretically. This generality makes the problem very difficult to formulate mathematically.

Even if the CCP's are only allowed at coal mines, the problem is very complex. It is a form of zero-one programming in that there are tow possible values at each coal mine or power plant (i.e., either the mine does or does not have a CCP, and either the power plant does or does not have an FGD).

In addition to the zero-one problem, the amount of coal from each source used at each plant is a significant variable affecting capital costs and operating costs as well as the constraints.

It was felt that arbitrary or heuristic selection of the locations of CCP's would permit formulation of the remaining problem, determination of coal amounts, as a linear programming package. This formulation would have the distinct advantage of permitting the use of powerful, existing computer solution packages such as IBM's Mathematical Programming System (MPS).

B-1 LINEAR PROGRAMMING FORMULATION

PEDCo Environmental's cost models were run for several different cases to determine the relationship of annualized cost of CCP's and FGD's to coal throughput or capacity. The cost curves were found to be approximately linear over a wide enough range to use linear programming. If the solution puts values outside this range, then coefficients can be adjusted and the solution recomputed.

The general linear programming formulation is expressed as: minimize total cost subject to the set of constraints. The total cost includes costs of (1) raw coal at the mine, (2) transportation to the power plants or CCP's, (3) coal cleaning, (4) transportation from CCP's to power plants, and (5) FGD's and ESP's (electrostatic precipitators) where applicable. Constraints employed included power plant (or boiler) capacity, network demand, SO_2 emission limitations, and coal washability characteristics. Other optional constraints utilized were mine capacity and derated boiler capacity when FGD was used.

A more specific discussion of the formulation will be facilitated by use of the network representation.

B-2 NETWORK REPRESENTATION

The network representation is a useful structure for formulating a large class of mathematical problems. A network consists of sets of nodes representing resources and/or facilities, and arcs representing possible routes the resources might take, connecting various pairs of the nodes.[1]

In the coal cleaning problem, coal mines, coal cleaning plants, and power plants are represented by nodes in the network. Arcs connecting these nodes are used to represent possible routes of coal. The network for a three mine, two plant scenario is shown in Figure B-1.

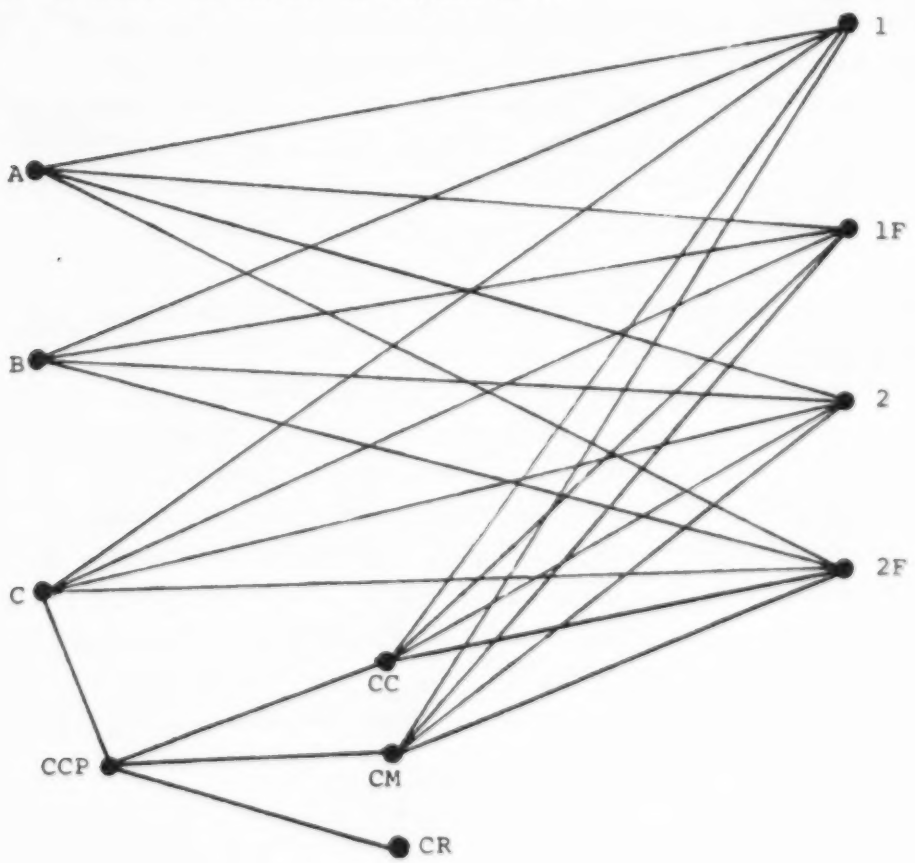

Figure B-1. Three mine, two plant network

In Figure B-1 the nodes representing coal mines are lettered A, B, and C. CCP designates the node representing a coal cleaning plant. Note that only coal from mine C may be sent to the CCP (representing a situation in which the coals from mines A and B are clean enough that physical coal cleaning is not desirable). The nodes CC, CM, and CR designate three output streams of the CCP: clean, middling, and reject, respectively, so that the routing of these streams can be represented in the network.

In order for the model to determine where FGD systems are used and to what extent, each power plant node is replaced by two nodes. These nodes can be envisioned as two boilers at the same plant, one with FGD and one without, and otherwise identical. In actuality a single boiler with an FGD can have some of the gases directed to the FGD and the rest vented directly to the ambient air. However, the two-boiler situation is easier to model. At plant 1, let the boiler without FGD be designated by node 1 and the boiler with FGD be designated by node 1F, and similarly for plant 2.

B-3 FORMULATION OF LINEAR COST FUNCTION AND CONSTRAINTS

Independent Variables

An independent variable can be associated with each of the arcs in the network. Each variable is to represent the flow of coal along that route. The units chosen for these variables were MM Btu since these units are appropriate both for measuring demand and emission limitations. Quantities expressed in tons or pounds are easily converted to MM Btu when the heating values are known. The cost function and constraints are linear expressions of the independent variables, wherein the coefficient of each independent variable is a constant.

Cost Function

Several functions for the various cost components were defined and summed to obtain coefficients of the independent variables for use in the objective functions. All costs were converted to $/MM Btu. The cost of raw coal at each mine was applied to the flow along each arc originating at that mine. Transportation costs reflected distances and mode of transportation and were assigned to each arc from mine to boiler or CCP and to each arc from a CCP output (i.e., CC, CM, or CR) to a boiler. No transportation costs are incurred on arcs from CCP to CC, CM, or CR as these routes are totally within the coal cleaning plant. These arcs from CCP to CC, CM, and CR were, however, assigned the coal cleaning costs, except that normally the reject stream was not considered a saleable product and was not assigned any portion of the coal cleaning cost. Finally, if any boiler had an FGD or ESP or both, those costs were allocated to all arcs terminating in the node representing that boiler.

Table B-1 lists all arcs and indicates the cost components allocated to flows along those arcs.

Constraints

This section discusses the constraints used in a basic model. Ways of adjusting these constraints to reflect various real situations will be discussed later. These basic constraints include several less than or equal relations: plant capacity, boiler capacity, mine capacity, emission limitations, and usage of CCP output. There is one greater than or equal constraint: network demand. We have also included a set of equality constraints describing the coal cleaning process. The constraints effecting each arc are shown in Table B-1.

For each plant, the sum of all flows into either node for that plant must be less than or equal to the plant

Table B-1. ARCS AND COST COMPONENTS ALLOCATED TO FLOWS

A1	Coal+Trans+ESP	Mine	Boiler	Plant	Network	SO_2
A2	Coal+Trans+ESP	Mine	Boiler	Plant	Network	SO_2
A3	Coal+Trnas+ESP	Mine	Boiler	Plant	Network	SO_2
B1	Coal+Trans+ESP	Mine	Boiler	Plant	Network	SO_2
B2	Coal+Trans+ESP	Mine	Boiler	Plant	Network	SO_2
B3	Coal+Trans+ESP	Mine	Boiler	Plant	Network	SO_2
C1	Coal+Trans+ESP	Mine	Boiler	Plant	Network	SO_2
C2	Coal+Trans+ESP	Mine	Boiler	Plant	Network	SO_2
C3	Coal+Trans+ESP	Mine	Boiler	Plant	Network	SO_2
A1F	Coal+Trans+ESP+FGD	Mine	Boiler	Plant	Network	SO_2
A2F	Coal+Trans+ESP+FGD	Mine	Boiler	Plant	Network	SO_2
A3F	Coal+Trans+ESP+FGD	Mine	Boiler	Plant	Network	SO_2
B1F	Coal+Trans+ESP+FGD	Min	Boiler	Plant	Network	SO_2
B2F	Coal+Trans+ESP+FGD	Mine	Boiler	Plant	Network	SO_2
B3F	Coal+Trans+ESP+FGD	Mine	Boiler	Plant	Network	SO_2
C1F	Coal+Trans+ESP+FGD	Mine	Boiler	Plant	Network	SO_2
C2F	Coal+Trans+ESP+FGD	Mine	Boiler	Plant	Network	SO_2
C3F	Coal+Trans+ESP+FGD	Mine	Boiler	Plant	Network	SO_2
CPCCP	Coal+Trans	Mine		Cleaning		
CCPCC	Cleaning	Cleaning		Conservation		
CCPCM	Cleaning	Cleaning		Conservation		
CCPCR	--------	Cleaning		Conservation		
CC1	Trans+ESP	Conservation	Boiler	Plant	Network	SO_2
CC2	Trans+ESP	Conservation	Boiler	Plant	Network	SO_2
CC3	Trans+ESP	Conservation	Boiler	Plant	Network	SO_2
CM1	Trans+ESP	Conservation	Boiler	Plant	Network	SO_2
CM2	Trans+ESP	Conservation	Boiler	Plant	Network	SO_2
CM3	Trans+ESP	Conservation	Boiler	Plant	Network	SO_2
CR1	Trans+ESP	Conservation	Boiler	Plant	Network	SO_2
CR2	Trans+ESP	Conservation	Boiler	Plant	Network	SO_2
CR3	Trans+ESP	Conservation	Boiler	Plant	Network	SO_2
CC1F	Trans+ESP+FGD	Conservation	Boiler	Plant	Network	SO_2
CC2F	Trans+ESP+FGD	Conservation	Boiler	Plant	Network	SO_2
CC3F	Trans+ESP+FGD	Conservation	Boiler	Plant	Network	SO_2
CM1F	Trans+ESP+FGD	Conservation	Boiler	Plant	Network	SO_2
CM2F	Trans+ESP+FGD	Conservation	Boiler	Plant	Network	SO_2
CM3F	Trans+ESP+FGD	Conservation	Boiler	Plant	Network	SO_2
CR1F	Trans+ESP+FGD	Conservation	Boiler	Plant	Network	SO_2
CR2F	Trans+ESP+FGD	Conservation	Boiler	Plant	Network	SO_2
CR3F	Trans+ESP+FGD	Conservation	Boiler	Plant	Network	SO_2

capacity, expressed in MM Btu. The coefficient of each variable is 1.

The sum of all flows into each boiler node must be less than or equal to the capacity (in MM Btu) of the boiler or boilers represented by that node. The coefficient of each variable representing a flow into a boiler node is 1 in the constraint for that node.

The sum of all flows from a mine must be less than or equal to the capacity of the mine. The coefficient of each variable representing the flow from a particular mine is 1 in the constraint for that mine.

The lb of SO_2/MM Btu burned at a particular plant must be less than or equal to the emission limitation (in lb SO_2/MM Btu) established by regulation. This relation must be transformed, however, to fit the units used in the linear programming formulation. The left-hand side is computed by multiplying the amount (in MM Btu) of each coal stream burned at a given plant by the lb of SO_2 produced by burning each MM Btu; this product is divided by the total amount of coal burned at the plant to give the actual emission rate in lb SO_2/MM Btu.

Multiplying the left-hand side by the denominator, the amount of coal burned, yields the total amount of SO_2 produced. Multiplying the emission limitations on the right-hand side by the total amount of coal burned results in the allowable SO_2 production at that level. This resulting right-hand side may be subtracted from both sides to obtain a constant right-hand side (zero) which is then in the standardized form necessary for input in MPS. The relation now states that excess SO_2 production (actual SO_2 production less allowable SO_2 production) must be less than or equal to zero.

The above inequality applies when no FGD is used to remove SO_2 after combustion. For every boiler with FGD, the corresponding term in the expression for actual SO_2 production must be reduced by the efficiency of the FGD system, assumed to be 85 percent in this study. Thus, each such term is multipled by 0.15 since only 15 percent of the SO_2 produced by combustion is released into the atmosphere when FGD is used.

Network theory requires that for every node with flows both in and out, there be a conservation constraint prohibiting any creation or destruction of the commodity in the flow, i.e., total flow in must equal total flow out. In our network, such nodes are the nodes associated with the outputs of the coal cleaning plant, CC, CM, and CR. To allow for disposal of some of this coal, a node could be created as a sink for unused coal. To simplify our network, however, we have chosen to use inequality constraints at CC, CM, and CR, i.e., flow out, must be less than or equal to flow in. It is understood that the difference between flow in and flow out represents unused coal. NOTE: without a sink for unused coal and arcs from appropriate nodes it is impossible to model the cost of storage, transportation, or disposal of unused coal.

Network demand is a greater than or equal to constraint. The sum of the outputs of all plants (or boilers) must be greater than or equal to the network demand in MM Btu. The output of any boiler is equal to the input in MM Btu multiplied by the efficiency of the boiler. The coefficient in this constraint of each variable representing the flow into any boiler would be unity if the efficiency of that boiler were 100 percent.

The set of constraints controlling the output of the coal cleaning plant reflects the washability characteristics of the coal being cleaned. When coal with known characteristics is cleaned, the amount of coal output in each stream per unit of raw coal can be predicted. This amount can be expressed in units of pounds of feed. Since we are assuming three output streams, the amount going to CC is a certain fraction of the flow into CCP, the amount going to CM is another fraction, and the amount to CR is the remainder. The heating values of the output streams are different from that of the input stream as a result of removal of sulfur and ash from the clean and middling streams. The constraints must be expressed in terms of MM Btu. The flow going to CC is equal to the fraction of the feed rate (in lb/100 lb feed) times 100 multiplied by the flow into the CCP converted to pounds by dividing by the heating rate (in Btu/lb) of the input stream. This flow is converted from pounds to MM Btu by multiplying by the heating value of the clean output stream. The coefficient of the variable representing the flow from CCP to CC may be given as -1, so that all variables are on the left-hand side of the equality constraint and the right-hand side is zero. The coefficient of the variable representing flow into the CCP is the fraction of the feed rate going to the clean stream (in lb/100 lb feed) multiplied by 100 times the ratio of the heating value of the clean output stream to the heating value of the input stream. Constraints on the flows going to CM and CR are formulated similarly.

B-4 MODIFICATIONS TO THE BASIC MODEL

The model described above was found to be quite flexible to variations imposed to take into account additional aspects of the real situation.

Boiler Derating

The efficiency of a boiler can be reduced when an FGD system is employed. This reduction is called derating. The RHS representing boiler capacity for boilers with FGD's (1F, 2F, . . .) can be reduced accordingly.

The model can be allowed to use FGD for any portion of the total capacity at a given plant by proper assignment of capacities. Let node 1 represent the combined capacity of all boilers at plant 1 if no FGD systems are used; then the capacity at node 1 will be equal to the total plant capacity. The capacity at node 1F may equal the total capacity of all boilers with FGD's, derated by a factor representing the decreased efficiency due to the FGD's. The sum of the flows to node 1 and node 1F will be less than or equal to the plant capacity because all of these flows are in the plant capacity constraint.

Mine Capacity

The mine capacity constraints are somewhat arbitrary. It may be hard to determine or estimate the capacity of a mine to deliver coal at a certain rate. If it is desired that limited mine capacity affect the solution, the capacity of each mine may be set slightly higher than the total network demand.

Purchased Power

Often, when a utility company cannot meet the demand with its own power plants, it will purchase power from another utility company. This can be represented in the model by a dummy mine node and dummy plant node disjoint from the rest of the network. The flow to this dummy plant is included in the network demand constraint, but there are no mine capacity, plant capacity, boiler capacity, or emission limitations on this arc. The cost associated with this

arc is the cost of the purchased power. This cost is high enough that the flow on this arc will be positive only if network demand cannot be met from other sources.